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The Honorable Chairman and Members of  
the Hawaii Public Utilities Commission  
465 South King Street  
Kekuanaoa Building, 1st Floor  
Honolulu, Hawaii 96813

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PUBLIC UTILITIES  
COMMISSION

Dear Commissioners:

Subject: Docket No. 03-0371 – Proceeding to Investigate Distributed Generation in Hawaii

Pursuant to the Commission's letter dated October 28, 2004, attached are  
HECO/HELCO/MECO's responses to the Commission's information requests.

Sincerely,

Attachment

cc: Division of Consumer Advocacy (3)

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PUC-IR-1

Do Hawaii electric utilities have authority under existing statutes and franchises to own distributed generation either directly or through an affiliate? If yes, please identify the specific statutes and franchises which authorize such activity. If no, please describe whether existing laws should be altered to permit utility ownership (either directly or through an affiliate) and if so, what changes are needed?

HECO Response:

In general, the Company does not need an explicit grant of authority to engage in an activity, unless there is a statutory or other restriction prohibiting such an activity without an explicit grant of authority.

For example, H.R.S. Section 269-7.5(a) requires a Certificate of Public Convenience and Necessity ("CPCN") issued by the Commission before commencing business as a public utility. Section 269-7.5(c) excuses the Companies from this requirement by virtue of their franchises.

Thus, if the retail sale of electricity to a customer by a non-utility third-party was deemed to be an electric utility service, the third-party would require a CPCN to offer such a service. (As is indicated in the Companies testimonies, HECO RT-6, page 9, lines 14-17.) The Companies would not require a new authorization to provide another electric utility service (such as the provision of CHP systems), but would have to comply with statutory and rule requirements with respect to tariff filings and approval of special contracts.

The Companies' franchises grant them the right to use public rights of ways, and impose franchise fees and certain service obligations in exchange for the grant. The franchises do not purport to limit the franchised utilities to owning and operating central station generating units,

or prohibit them from owning and operating customer-sited generating units (or prohibit them from engaging in other activities, including non-utility activities). (HECO RT-1, page 34-35.)

The Companies were asked in an information request whether their position on utility CHP system ownership was consistent with HAR § 6-74-7. HAR § 6-74-7 is part of subchapter 2 of Chapter 74, Title VI, which applies to the criteria for and manner of becoming a “qualifying small power production facility” and a “qualifying cogeneration facility”. HAR § 6-74-2. In order to be a qualifying facility (“QF”), a “small power production facility” and “cogeneration facility” must meet the ownership criteria specified in HAR § 6-74-7. See HAR § 6-74-4(a)(3), (b)(2). Section 6-74-7(a) merely provides that neither a cogeneration facility or a small power production facility meets the ownership criteria to be a QF if the facility is owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities). Section 6-74-7(b) defines, for purposes of § 6-74-7, when a facility is considered to be owned by a person primarily engaged in the generation or sale of electric power.

The Hawaii PUC adopted its rules under a provision in the Public Utility Regulatory Policies Act of 1978 (“PURPA”) requiring that state commissions implement rules adopted by the Federal Energy Regulatory Commission (“FERC”), and § 6-74-7 is identical to the FERC rule found in 18 CFR § 292.206. In adopting its rule, FERC apparently recognized that someone might attempt to misinterpret the rule, and explicitly stated that: “The Commission emphasizes the fact that nothing in this program limits the extent of utility ownership or operation of cogeneration or

small power production facilities.” 45 Fed. Reg. 17959, 17971 (March 20, 1980) (See response to LOL-SOP-IR-81.)

PUC-IR-2

Are there any changes required to existing statutes, rules, or regulations to facilitate non-utility ownership of distributed generation (“DG”) facilities?

HECO Response:

No changes are required. Existing statutes, rules, and regulations adequately provide for non-utility ownership of DG. In its testimony, the Companies explained in detail how the proposed utility CHP Program would not unfairly impact non-utility developers of DG/CHP and competition would exist in the market. In fact, there are circumstances that make it more challenging at times for the utility to develop CHP than a non-utility. Non-utility CHP systems may offer quicker installation schedules compared to utility systems, to the degree that the utility needs to obtain PUC approval for projects done under Rule 4. The non-utility provider may also have more flexibility in providing additional services and equipment that would otherwise be considered below the line from the utility’s standpoint. Unregulated competitors can also offer their products and services without open review of their prices or terms and conditions of services, as must be done by the utility before the Commission. (See HECO RT-1, pages 21-34) Non-utility DG developers are not competitively disadvantaged when compared to the regulated utility’s own development of DG, especially with regard to large national DG developers that are established in Hawaii. (HECO RT-1, page 33)

PUC-IR-3

What is the impact of Hawaii's net energy metering law, codified at Hawaii Revised Statutes ("HRS") § 269-101-111, ( and recently amended this past legislative session to allow eligible systems of up to 50 kilowatts ("kW") to sell excess energy to the utility) on customer decisions to invest in DG? Should the existing 50 kW size limitation be increased to facilitate DG? Should the existing net energy metering law be expanded to include technologies other than those specified in the statute? Please identify any other changes that should be made to net metering laws, and why?

HECO Response:

The net energy metering ("NEM") law has the potential to impact customer decisions to invest in DG that falls within the scope of the law. HECO acknowledged that tax credits and NEM can help reduce the costs of eligible renewable energy systems (solar, wind, biomass, hydroelectric or combinations of these technologies), including grid-connected PV systems (see HECO T-2, pages 22-23 and IR response to HREA-HECO-T-2-IR-10). However, the decisions by customers to invest in NEM-eligible DG systems may depend on other factors, such as environmental or social principles, and may or may not be solely dependent on being eligible for NEM.

At the end of 2003, the number of reported NEM installations was 31 for HECO, HELCO and MECO systems (total of about 92 kilowatts). All of these installations used photovoltaic systems and the average size was less than three kilowatts. The 2004 Legislature updated the NEM law to further help renewable energy development in Hawaii. In general, the update increased the allowable size of renewable energy technologies in the NEM law from 10 kW to 50 kW (see HECO T-2, pages 22-23 and HECO RT-6, pages 10-11).

Any further changes at this time to the net energy metering law (e.g., increasing the size limitation) would be premature, since the current legislative change has been in effect for less than a year. The net energy metering law was amended by Act 99, Session Laws of Hawaii,

effective June 2, 2004. Under Act 99, the net energy metering law was amended to increase the size of the facilities qualifying for net energy metering from 10 kilowatts to 50 kilowatts. HECO supported expansion of the 10 kW limit to 50 kW this past legislative session, recognizing that the 50 kW amount may introduce interconnection considerations that are different than those associated with 10 kW facilities (see HECO RT-6, page 11). HECO understood the Hawaii State Legislature's desire to increase renewable energy development via the NEM law rather than the broader DG technologies.

There are concerns with increasing the size limit beyond 50 kW. For example, as the size of NEM systems increase, interconnection of the customer generator with the utility grid increases in complexity. A large-scale installation will likely have unique interconnection considerations depending on its size and location on the system, and safety becomes an issue. As larger NEM systems are considered, it is important to understand safety, reliability, and power quality issues. The PUC has recently approved new interconnection standards and a standard interconnection agreement for generators operating in parallel with the Companies' utility systems (as specified in Rule 14 Section H, Decision and Order No. 20056, Docket No. 02-0051, approved by PUC on March 6, 2003). The 2004 Legislature updated the NEM law which states that the larger generators (greater than 10 kW) can follow these interconnection procedures as approved by the PUC, including the customer insurance requirements. The new NEM statute will help ensure interconnection issues such as power quality, protection of both utility and customer equipment, reliability, and safety of maintenance workers are taken into consideration.

PUC-IR-4

Should the Commission define distributed generation – and if so, how should it be defined? Should the definition be flexible or specific as to size and technology? Should the definition identify “eligible” technologies – and if so, how would such a list be derived? Or should the definition be sufficiently flexible to apply to a range of DG technologies, both those currently feasible as well as those not yet developed?

HECO Response:

As defined by the Commission in this Docket, DG involves the “use of small-scale electric generating technologies installed at, or in close proximity to, the end-user’s location”. For purposes of this docket, the Companies believe that this definition is sufficient. A more detailed definition of DG (e.g., identifying eligible technologies) would be necessary only if the Commission intends to somehow regulate or limit utility activities pertaining to DG, and develops specific rules or policies for particular types or sizes of DG. Under HECO’s proposed CHP Program and Schedule CHP tariff, a definition of DG is unnecessary as the proposed Program clearly delineates the CHP technology and its application.

PUC-IR-5

Should the definition of distributed generation include DER, “distributed energy resources” and other demand side technologies or systems?

HECO Response:

No. “Distributed generation” should refer to generation technologies only, in other words resources that supply energy. DG is broadly understood to be a subset of DER. Other DER subsets, such as demand side management (“DSM”) and energy storage technologies, are not DG.

DG should not be confused as a DSM measure. Extensive testimony was given at HECO RT-1 pages 42-48 to explain why DG is not similar to DSM measures or programs. DSM Programs are designed to influence the use of energy. DG is a resource that supplies energy. The distinction between the use and supply of energy was made by the Commission in its Framework for Integrated Resource Planning (“IRP”) (Decision and Order No. 11630, Docket No. 6617). (HECO RT-1, page 43.) The Companies maintain that the inclusion of the word “uses” in the IRP Framework implies that the framework intended to apply the term “DSM” only to those measures that affect how companies use energy, not how it is generated.

Differences also exist between DSM measures and DG resources in terms of ownership, operation and maintenance. The measures installed pursuant to energy-efficiency DSM programs generally are replacements for equipment, fixtures, or processes that are used in the customer’s business or home, such as energy efficient lighting, or motors, or water heaters. Thus, DSM measures generally can be “operated” and “maintained” (to the extent that is necessary) using the O&M expertise or resources that the customer already has. These DSM measures, which allow electricity to be used efficiently, or substantially reduce the use of

electricity (such as is the case with solar water heaters, where electricity is the back up water heating source), are distinctly different from DG resources, which generate electricity. The option of utility ownership of a DG resource, such as a CHP system, is desirable to customers precisely because they often do not want to own, operate and maintain generating resources. (HECO RT-1 pages 43-44.)

Major differences exist between the Companies' proposed CHP Program and their DSM programs, such as the Residential Efficient Water Heating ("REWH") Program, which provides incentives to customers who install solar systems. Some major differences between these two types of programs include:

1. CHP systems produce electricity, generally cost in the hundreds of thousands of dollars, are operated, and require extensive periodic maintenance. (See response to TGC/HECO-SOP-IR-24, subpart b.) Solar systems heat hot water, generally cost only several thousand dollars, and do not require operation or extensive maintenance.
2. There are a limited number of vendors offering CHP systems, and to date there have been only a small number of CHP systems installed in Hawaii, and the Companies expect that their involvement in the CHP market on a regulated basis will result in an expanded market. Under the Companies' REWH Programs, over 20,000 solar systems have been installed statewide, and it is estimated that there are some 80,000 solar systems in operation statewide, indicating there is a broad market with numerous solar vendors.
3. In the design of the Companies' CHP Program, because of the more limited opportunities for customers to participate in the CHP Program (i.e., many commercial and industrial customers do not have a use for the waste heat from the CHP systems that precludes them from participating in the program), the impact to non-participants was explicitly taken into consideration such that participants as well as non-participants benefit from the Companies' involvement in the CHP market on a regulated basis. The impacts to non-participants were accepted in the REWH Program because there are more broad based opportunities for customers to participate in the program, and also because the program furthers the State's goals of renewable energy and a reduction in the use of fossil fuels.
4. If the Companies provided an incentive to customers to install a CHP system, and had no further involvement with the operation and maintenance of the CHP system, there would be no assurance that the CHP system was being properly maintained in order to provide the expected reduction of the peak on the utility system from the CHP system operation. Solar systems, as stated above, do not require extensive maintenance and have a

reasonable track record with providing the expected reduction in electricity usage and corresponding system peak reduction.

5. The Companies' CHP Program entails utility ownership of a limited number of CHP systems in order to achieve the intended results. It would be impractical for the Companies to own thousands of solar systems.

Further, unlike the Companies' proposed CHP Program, DSM programs are not currently designed so as to avoid any "burden" on non-participants. Incentives are paid to customers for "cost effective" programs, even where individual customer rates are increased when the utility recovers the program costs and lost contributions to fixed utility costs. (On a total customer basis, energy bills should be reduced because of the reduction in energy use.) Whereas all customers benefit from the demand savings (i.e., the kw savings) resulting from DSM program measures, participating customers are the primary beneficiaries of the energy savings. (At the same time, there is a benefit to the State as a whole, including non-participating customers, due to the reduction in the use of oil.)

As is indicated above, one of the primary justifications for the current approach to DSM programs is that there is a broad array of DSM measures available under the DSM programs, and a broad opportunity for customers to participate (and to directly benefit from bill savings).

In the case of CHP systems, all customers will benefit from the capacity deferral benefits that can be obtained from the installation, operation and maintenance of energy-efficient CHP systems, but only a relatively small number of customers have the opportunity to directly achieve energy cost savings through the installation of such systems on their sites. Thus, unlike the case with DSM programs, one of the key objectives of the CHP program is to avoid burdening non-participating customers. (HECO RT-1, pages 46-47)

PUC-IR-6

Should the Commission draw a distinction between “small scale” DG and other DG resources and if so, why? How should “small scale” DG be defined? What benefits can small scale DG offer (e.g., firm power, increased reliability, reduce transmission constraints) and what impacts does it have on the system?

HECO Response:

The need to distinguish between “small scale” and other DG resources is dependent on whether the Commission intends to develop regulation or policy that pertains to a specific size of DG.

All DG by definition should be small scale, however, as the Companies pointed out in this Docket, “small” should be construed relative to the utility’s system loads and to the loads of the customer being served.

As for defining an upper size limit on DG, the Companies stated in response to CA-IR-1:

“The Companies have not formally defined size limits for DG on each of the islands. Notwithstanding this, it would be reasonable to consider both total system load and, for customer-sited DG, the load of the customer, the nature of the DG technology being applied, and the purpose of the DG application.

Regarding system load, it is useful to compare DG by service area with a total capacity of one-half to one percent of total system load, since few individual customers will have larger loads. For example, Oahu’s recorded peak demand in 2003 was 1,242 MW-net<sup>1</sup>, which would suggest an upper range of DG of 6 to 12 MW per site. It is possible that generating capacity of this size could be installed to serve the internal loads of some of HECO’s largest customers. For Maui, the peak demand recorded in 2003 was 198 MW-net, suggesting an upper range of DG of 1 to 2 MW. The two 1 MW generators installed at Hana (as referred to in HECO T-1, page 6, lines 15-18) fit this range. For the Big Island, the peak demand recorded in 2003 was 186 MW-net, also suggesting a 1 to 2 MW per site upper range for DG.

For Molokai and Lanai, the peak demand recorded in 2003 was 6.6 MW-gross and 5.1 MW-gross, respectively. For these islands, applying the system load “rule-of-

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<sup>1</sup> With Chevron, Tesoro and Pearl Harbor generating an estimated 21 MW of power at the time. Had they not been generating power, the peak would have been 1,263 MW-net.

thumb” would suggest an upper range of DG of 25 to 66 kW. However, in this instance, customer load and the nature of a DG technology should also be considered. For example, a hotel on one of these islands may well benefit from a CHP installation, provided the hotel’s loads and thermal energy uses are large enough to allow installation of a cost-effective CHP system. As stated on page 22 of HECO T-1, CHP installations below about 200 to 250 kW may not be economical. Hence, for Molokai and Lanai, DG may well end up in the range of a few hundred kW.

The above discussion is general in nature and is not meant to serve as a rigorous basis for defining DG. As DG project opportunities occur, site-specific factors will always need to be considered which will influence the size of the installation.”

The generic benefits of DG were outlined in the Companies’ written direct testimony at HECO T-1 page 14, and are as follows:

- Deferral of new central station generating capacity;
- Displacement of utility central station generation fuel and variable O&M costs;
- Deferral of new transmission and distribution (“T&D”) capacity; and
- Improved T&D system reliability and power quality.

These benefits, however, are contingent on the reliability of the DG, and the degree to which the utility can control the operations and maintenance of the DG system.

On the flip side, DG, if not properly designed, operated, maintained, and interconnected, can have negative impacts to electric system reliability and power quality. As described in HECO T-4, “depending on where it is installed, DG can affect the reliability of a single customer’s electric service or have an affect on the T&D system. The initial installations of small-scale DG units at customers’ sites (for other than emergency backup) were often problematic for both the customer and the utility. From the customers’ standpoint, there were performance problems with the units, with the fuel for the units and with the maintenance of the units. A number of initial units are no longer operable and/or have been replaced such as the HESS installed units at the University of Nations and at the Hualalei Regency. From the T&D

system standpoint, unexpected outages that could be caused by poor unit performance or maintenance practices can adversely impact local voltage and frequency control.” (HECO T-4, page 2)

HECO T-4 also described the very complex potential impacts of DG facilities on power quality. The impacts are complex due to numerous location specific issues such as:

- configuration of the distribution system, radial vs. network
- length of distribution lines
- penetration of distributed generation on the primary circuit and the back up circuit
- reliability and redundancy of customer systems
- synchronous or induction generation
- grounding of transformers and other equipment
- short circuit characteristics of the distribution circuit.

For example, the DG interconnections can cause an increased risk of voltage regulations problems, adverse interactions with the utility’s protection system and unintended islanding as the penetration DG capacity increases on a utility distribution feeder. Therefore, Rule 14H provided a need for additional technical study for distributed generation to examine the risk of these problems when the aggregate generating capacity per distribution feeder exceeds 10% of the peak annual KVA load of the feeder. (HECO T-4, pages 25-26)

The ability of the utility to directly control the operations and maintenance of a DG system will improve its impacts on system reliability and power quality. As described in the Companies’ response to CA-IR-13, if the DG system is designed and installed in a manner consistent with utility standards, then in general, the same impacts and benefits could be derived from a non-utility DG system as a utility DG system if the utility is directly in control of the operations and maintenance of the system. If the system is not consistent with utility standards,

for example, sub-standard components are used causing more frequent breakdowns, there may still be adverse impacts on system reliability and power quality even if the utility is given control over operations and maintenance.

A third-party CHP system would be operated to maximize benefits to the customer and the CHP system owner. The utility-owned CHP system would be operated and maintained to balance the customer benefits with the overall utility operation. As examples, having real-time dispatchability of the CHP units as described below differentiates the utility-owned and operated CHP systems:

- Voltage support: the utility CHP system would standardize the use of synchronous generators. This would allow limited customer and regional voltage support benefits.
- Control logic dispatch: the Companies are still finalizing their preferred CHP unit dispatch parameters, but is considering control system modifications to allow (4) control modes for utility CHP systems which are not currently used on any of the third party installed CHP systems in Hawaii:
  - Normal: the CHP power output would be balanced with the customer's thermal load to minimize the dumping of excess waste heat.
  - Peaking: on command, the CHP unit would maximize its power output without backfeed to the grid. This would provide system generation capacity support and/or support regional distribution system load in the event of a secondary feeder outage or temporary high loads.
  - Minimum: on command, the CHP unit would minimize its power output. This mode is targeted to the neighbor island systems where on-line regulating units may already be at minimum load and backing off the CHP units would allow greater operating margin on the regulating units.
  - Shutdown: utility system operators would be able to remotely shut-down each CHP system due to local network problems and lineman safety.

The maintenance of utility-owned and operated CHP systems would allow the scheduling of maintenance outages to minimize conflicts with distribution system maintenance

work and other utility system considerations where regional distributed generation would support the local power quality and reliability. (See response to CA-IR-13)

PUC-IR-7

Please comment on HECO's listed criteria (see e.g. Seki Testimony at 20) for determining whether a DG technology is "viable and feasible" for Hawaii. Should other factors be considered as well?

HECO Response:

HECO's testimonies provide a sound basis for evaluating whether a DG technology is "viable and feasible" for Hawaii (see HECO T-1, pages 7-8, HECO T-2, page 20, and HECO RT-2 page 7, IR response to HREA-HECO-T-2-IR-7).

The Companies emphasize, however, the importance of recognizing that customer preference and market demand plays a significant role in determining whether a form of DG is feasible and viable for Hawaii. The seventh criterion, the ability of the DG to meet the needs of the customer, is an absolute requirement for customer-sited DG. For customer-sited DG applications, the decisions to install customer-sited generation, the type of technology, and the ownership option, will be made by the customers allowing the installation of such generation. (HECO RT-1, page 38)

Each customer will weigh different factors when considering whether or not to go forward with a form of DG. As stated on page 38 of HECO RT-1:

"customers generally will not consider technologies that are not technically feasible or commercially available or that are not able to address site-specific constraints (although this factor will vary among customers because it is site-specific). Some customers will be more concerned with life-cycle costs, while others will focus on upfront costs. (HECO T-1, page 8, lines 8-18.) Reliability is a more important customer need for some customers than for others, because of the differences in their business operations. A few customers may give more weight to externalities. (Response to CA-SOP-IR-2.) These are not the only factors that customers will take into account in deciding to install customer-sited generation. They will consider whether they are expanding or renovating their operations (HECO T-6, page 5.) They will consider the vendors and types of vendor offerings available to them. (HECO T-1, pages 24-26.) "

PUC-IR-8

Have the “multiple benefits” of DG cited in Life of the Land’s testimony (Wooley at 2) ever been quantified for Hawaii as they have in the other states mentioned in the testimony and if so, where can this information be found?

HECO Response:

Ms. Jessica Wooley’s rebuttal testimony states on page 3<sup>1</sup>, lines 8 to 12, that “As reported and quantified in many states, this kind of shift in energy production creates significantly more local jobs, greater earnings, and greater economic output. Although these multiple benefits have not been estimated in Hawaii (to my knowledge), they should be quite large and beneficial to Hawaii’s economy.”

As part of HECO’s IRP-3 effort, which is currently on-going, HECO contracted the University of Hawaii Economic Research Organization (‘UHERO’) to perform a study to quantify the effects on the Hawaii economy of alternative resource plans. The study will quantify the effects on parameters such as economic activity (Gross State Product) and employment. UHERO has compiled preliminary results and presented them to the HECO IRP-3 Integration Technical Committee on November 8, 2004 and to the IRP-3 Advisory Group on November 15, 2004. Integration Technical Committee and IRP Advisory Group member input will be considered in preparing the final report, which should be available in the first quarter of 2005.

Please also refer to HECO’s response to LOL-SOP-IR-71 in which Life of the Land asked questions related to “the multiplier effect job creation and economic growth, fuel volatility and security.” HECO responded: “It is not clear the type of comparisons of alternative technologies

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<sup>1</sup> The Commission’s question refers to “Wooley at 2.” However, Ms. Wooley’s statements on “multiple benefits” in other states appear on page 3. It is the statement on page 3 to which HECO is responding.

that are being referenced in this IR. The effects of different resource plans (which may include different resources) on the economy may be considered in IRP. See, for example, HECO's second IRP filed January 30, 1998 in Docket No. 95-0347, HELCO's second IRP filed September 1, 1998 in Docket No. 07-0349, MECO's second IRP filed May 31, 2000 in Docket No. 99-0004, and the Hawaii Externalities Workbook filed July 22, 1997 in Docket No. 095-0347. Assuming this IR is referring to comparisons of distributed generation technologies in this docket, macro-economic impacts of distributed generation could be covered as part of Issue 7, (i.e., What are the externalities costs and benefits of distributed generation?)."

Please also refer to HECO's response to LOL-WDT-IR-34 in which Life of the Land posed the question "Do positive externalities include price stability; balance of trade issues; and decreasing the leakage of money from the state economy." HECO responded: "Economic impacts of DG may be considered as externalities. See response to LOL-SOP-IR-71, for example. The Companies would not support blanket statements regarding the positive (or negative) association between all forms of DG and "price stability; balance of trade issues; and decreasing the leakage of money from the state economy". See for example, the response to HREA-HECO-T-1-IR-4 regarding balance of trade and "export" of money from the state economy."

In HREA-HECO-T-1-IR-4, HREA posed the question "On page 11 (line 11+), aren't there also negative economic impacts associated with our continued use of fossil fuels, e.g., negative impacts of exporting our dollars for foreign oil and coal?" HECO responded: "There are negative economic impacts to the degree any dollars are "exported" outside our local economy whether it be for fuel, services, or equipment. This applies to all forms of energy production, both fossil fuel and renewable. It is disingenuous to focus on only one aspect—fuel cost—when considering

economic impacts of energy production alternatives. As an example, comparing a fossil fuel generator with a photovoltaic system, both systems are manufactured outside of Hawaii and so one can consider the equipment dollars to be exported. Yet on a cost per kilowatt-hour basis, the fossil fuel generator is cheaper than the photovoltaic system and one could argue that therefore, fewer dollars are being exported using the fossil fuel system.”

PUC-IR-9

Please identify any additional information provided in response to any party's Information Requests or filed in other dockets that provides further documentation or evidence of:

- a. whether there are transmission, distribution generation constraints which could be served by DG;
- b. the extent to which load growth is driving the need for distribution system enhancements;
- c. where DG should be located to be most effective (and documentation for this conclusion); and
- d. the availability or feasibility of alternative technologies.

To the extent that your testimony or prior responses do not already provide sufficient detail on these issues, please supplement your testimony with information on the above points.

HECO Response:

- a. In response to CA-SOP-IR-21, the Companies listed several Dockets and studies which identified transmission problems including Docket No. 03-0417 (East Oahu Transmission Project), Docket No. 03-0388 (Kailua Capacity Addition) and the draft 7200/7300 Line Overload Study. In addition, attached is the Executive Summary of the 10 Year Transmission Study (2004-2013) for the MECO system, which identified line overload and voltage problems on the 69kV transmission system in Central Maui, East Maui, West Maui and South/Up-country Maui. Distributed generation ("DG") was evaluated as an option for the East Oahu Transmission Project, the draft 7200/7300 Line Overload Study and in the 10 Year Transmission Study for the MECO system. In Docket No. 03-0417, Exhibit 6, the effectiveness of DG was analyzed to address the Koolau/Pukele Line Overload Situation. (Reference Docket No. 03-0417, HECO T-4, pages 81-83.) As stated in HECO T-4, pages 11-12, the study concluded that only 19 MW, which was half of the 47 MW required to defer the Koolau/Pukele Line Overload, could possibly be installed to reduce the load

growth in the Koolau/Pukele area, but was not practical due to space and permitting issues and cost.

DG and CHP was also evaluated in the draft 7200/7300 Line Overload Study. The 7200 line and 7300 line are two of three 69kV transmission lines on the HELCO system currently experiencing overload conditions under single contingency situations as explained in Docket No. 03-0388 (Kailua Capacitor Addition), Exhibit IV. Excerpts of the DG analysis from the draft 7200/7300 Line Overload Study was attached to the response to CA-SOP-IR-15. As stated in HECO T-4, page 12 the conclusions from the draft 7200/7300 Line Overload Study DG analysis are 1) that it is not realistic to assume that HELCO will be able to site the necessary DG units to prevent the line overload situation at HELCO owned substation sites on the Kona coast and 2) there will not be sufficient utility-owned CHP installed early enough to reduce the line overload on the 7300 line as a result of the 7200 line contingency and that it may require years (~2016) before the utility-owned CHP installations match the requirements needed to defer the overload situations.

The 10 Year MECO Transmission Study included an analysis of CHP in specific areas. The attached Executive Summary from the report concluded that CHP in specific areas of the MECO system could 1) affect the timing of the next generating unit and therefore could defer low voltage problems in the West Maui area, which is where the CHP systems were assumed, beyond the 10-year study period and therefore defer the need for additional capacitors, and 2) defer the need for a 69kV transmission line from Maalaea Generating Station to Kihei for approximately 9 years although capacitors would still be required. The study did not assess if it was practical to install the forecasted CHP systems in specific areas of the MECO system because of factors such as land requirements, permitting and costs

associated with installing the CHP systems. Therefore, there is some uncertainty in terms of where and when CHP systems will be installed. Installing CHP in other areas of the MECO system could also accelerate transmission system violations. Refer to PUC-IR-12.

As stated in response to CA-SOP-IR-15, currently there are no identified distribution circuits in which upgrades could be deferred by the installation of DG units. Planning for the distribution system, however, is an on-going process and distribution projects are currently being reviewed. The HECO distribution planning process does consider the installation of CHP and DG as an option in its planning process as explained at the April 23, 2004 IRP Advisory Group Technical Committee meeting. Refer to HECO-R-400, pages 1-30 for a copy of the presentation. HELCO and MECO distribution planning is also an ongoing process and the process will consider distributed generation as a planning option in future analyses.

- b. The need for distribution enhancements is driven by load growth. As stated in HECO RT-4, pages 8-9, load growth on the distribution system is dependent on customer project developments and can be attributed to the addition of new customers or increases in demand from existing customers. These project developments progress at varying time schedules and can change in size. Therefore, planning for the distribution system is an on-going process and distribution projects are currently being reviewed. Distribution enhancements can also include upgrading the existing system or branching out the distribution system to new areas. For instance, West Oahu has experienced new load additions of residential housing units and small commercial developments in which line extensions were required. Extensions of the 25kV system were recently required for the Walmart/Sams Club at Keeamoku and underground distribution extensions on the 12kV system were also required

to serve the new State Commercial Fishing Village located at the piers along Nimitz Highway.

- c. Please refer to the response to CA-SOP-IR-15, CA-SOP-IR-21 and subpart a. of this response.
- d. It is assumed that the question is referring to the availability and feasibility of various forms of DG technologies. HECO's Preliminary Statement of Position (pages 3-6) explains various DG technologies and feasible technologies on other utility systems as well as for Hawaii. Also refer to HECO T-1, pages 5-11, HECO T-2, pages 1-22, HECO RT-2, pages 7-9, responses to CA-IR-23 and CA-IR-27.

## **1. Executive Summary**

### **1.1 Scope**

Evaluate the Maui Electric Company (MECO) Transmission System requirements for the ten-year period covering 2004-2013. Identify violations to the MECO Transmission Planning Criteria and recommend solutions to alleviate these conditions.

### **1.2 Results and Conclusions**

Within the next ten years, the MECO generation system is anticipated to experience several changes. Among these changes are the potential installation of a Wind Farm at Kaheawa, the possible expiration of the HC&S contract, and the anticipated installation of a new Unit at Maalaea Generating Station (MGS) and the new Waena Generating Station (WGS).

The MECO transmission system may also require some major changes in the next ten years including shifting load from the 23 kV to the 69 kV system in the Central Maui area and adding a new transmission line in the South Maui area.

Also impacting the MECO system is the anticipated addition of Combined Heat and Power (CHP) units. Depending on the amount and location of CHP installed on the MECO system, they have the potential of deferring new MECO generation units and other capital additions to the transmission system.

The MECO system was divided into four areas for analysis purposes: (1) Central; (2) East; (3) West; and (4) South/Up-country Maui.

The following is a summary of the overloads and voltage problems identified for each area and the solutions proposed to alleviate each situation for the years 2004-2013.

Additional scenarios were performed to determine the sensitivity of the results to the addition of CHP units and continuing HC&S beyond 2007.

#### **Area (1): Central Maui**

The 23 kV system in this area is heavily loaded especially at the Wailuku and Kahului Substations. This is anticipated to cause overloading of the 69-23 kV

tie transformers as well as the 23 kV lines in this area during contingency situations. The loss of the MGS-Waiinu 69 kV Line is also anticipated to cause several voltage problems in this area, as this line is a major source of VAR support for the 23 kV system.

Under normal conditions, no overloads or voltage problems are anticipated.

To alleviate the problems identified, some capacitor bank additions are recommended. Existing load should also be shifted away from the 23 kV to the 69 kV system starting in 2006.

New load additions in this area should be served from the 69 kV system rather than adding them to the 23 kV substations in this area to avoid accelerating anticipated overloads on the 23 kV lines and tie transformers in future years during contingency situations.

Including CHP impacts defers the installation date of WGS Unit 1, which resulted in some capacitor bank installations being required sooner.

Including HC&S for the duration of the 10-year study period did not affect the results for this area.

#### Area (2): East Maui

There are several anticipated low voltage problems in this area due to high losses caused by the heavy loading at Makawao and Haiku Substations as well as the long circuit to Hana Substation.

Under both normal and contingency situations, no overloads are anticipated.

To alleviate the problems identified, several capacitor bank additions are recommended.

Under emergency conditions, there is the possibility that the entire East Maui load may need to be served either from Kanaha or Pukalani Substations. These situations were not studied in depth in this report. If the system needs to be designed to meet the MECO Transmission Planning Criteria during these conditions, a separate study should be initiated to review these requirements in detail.

Including CHP impacts defers the installation date of WGS Unit 1, which resulted in several capacitor bank installations being required sooner.

Including HC&S for the duration of the 10-year study period did not affect the results for this area.

Area (3): West Maui

With the addition of the third 69 kV Transmission line from MGS to West Maui, there are no anticipated problems in this area until 2013 when low voltages are anticipated to occur for a single-line out contingency.

Under normal conditions, no voltage problems are anticipated.

Under both normal and contingency situations, no overloads are anticipated.

To alleviate the voltage problems identified, some capacitor bank additions are recommended.

Using the CHP impact for the West Maui area assumed for this study deferred the low voltage problem beyond the 10-year study period.

HC&S had no impact on the system conditions in the West Maui area.

Area (4): South/Up-country Maui

The heavy loads at Kihei and Wailea Substations and the anticipated addition of Piilani Substation in 2005 are anticipated to cause overloading of the lines in this area by 2009 during single-line out contingencies. Low voltages are also anticipated to occur by 2005 during an outage of the MGS-Piilani 69 kV Line.

Under normal conditions, no overloads or voltage problems are anticipated.

To alleviate the problems identified, a new line should be installed between MGS and Kihei Substation by 2009.

During the interim before the new line is built, additional capacitor banks should be installed in 2005 at Kihei and Wailea Substations to help improve voltages during an outage of the MGS-Piilani 69 kV Line. This is only a temporary solution and some risk is involved as low voltages are still anticipated to occur until the new line is installed.

Using the CHP impact for the South Maui area assumed for this study deferred anticipated line overloads in this area beyond the 10-year study period, however low voltages still occurred by 2005. The additional capacitor

banks at Kihei and Wailea Substations were still required in 2005, however the need for the new line from MGS to Kihei was deferred until 2012.

Including HC&S for the duration of the 10-year study period did not affect the results for this area.

### 1.3 Recommendations

The following is a summary of the recommended MECO system revisions/ additions for the next 10 years and ballpark estimates for those recommendations that will have a Capital cost.

The years shown in parentheses () indicate the recommended year if CHP impacts are considered:

	<u>Yr</u>	<u>Recommendations</u>	<u>Ball Park Capital Cost</u>
(1)	2004	Leave one 3.6 MVAR capacitor bank at Wailuku Substation (3) on all of the time. Second 3.6 MVAR capacitor bank at Wailuku Substation and 3.6 MVAR capacitor bank at Kahului Substation (8) should be switched on during Peak load.  May need to raise voltage at Kahului Generating Station (KGS) to maintain acceptable PF.	\$0
(2)	2004	Raise Wailuku Substation Transformer #3 & #4, Kahului Substation Transformer #3, and Waiehu Substation Transformer NLT positions to Tap 1.	\$0
(3)	2004	Raise Pukalani 69-23 kV Tie Transformer LTC set point to keep the 23 kV bus voltage at approximately 23.5 kV (1.02 p.u.). Monitor the LTC position to determine if NLT position needs to be changed.	\$0
(4)	2004	Raise Haiku Substation Transformer NLT position from Tap 3 to Tap 1.	\$0

	<u>Yr</u>	<u>Recommendations</u>	<u>Ball Park Capital Cost</u>
(5)	2004	Existing 3.6 MVAR capacitors on Kihei Substation Transformers #1 (Bkr. 1254) & #2 (Bkr. 1385) and Wailea Substation Transformers #1 (Bkr. 1280) & #2 (Bkr. 1321) should all be switched on during Peak load	\$0
(6)	2005	During Peak load conditions for an outage of the MGS-Waiinu 69 kV Line, use the Waiinu Tie Transformer LTC to raise the Waiinu 69 kV bus voltage by locking the LTC near the lower 8 position.	\$0
(7)	2005	Install 1.2 MVAR of capacitors at Makawao Substation (12).	\$15,000
(8)	2005	Raise Makawao Substation Transformer NLT position from Tap 3 to Tap 1.	\$0
(9)	2005	Install 3.6 MVAR of capacitors on both Kihei Tsf #3 and Wailea Tsf #3. These capacitor banks are only required until the MGS-Kihei #2 Line is built.	\$325,000
(10)	2006	Transfer about 1 MW of load from both Wailuku (3) and Kahului (8) Substations to Waiinu 69 kV.	Unknown*
(11)	2006	Relocate existing Waiinu Substation 69/23-12kV Transformer #2 to the 69 kV Bus. This transformer may need to be replaced with a larger MVA rated transformer. Substantial modifications of Waiinu Substation (36) will also be required.	\$875,000
(12)	2009 (2012)	Install new MGS-Kihei 69 kV Line #2. Substantial modifications of Kihei Substation (35) will also be required to accommodate the termination of the new line.	\$6,200,000
(13)	2009	Install 0.6 MVAR of capacitors at Hana	\$6,000

	<u>Yr</u> (2008)	<u>Recommendations</u> Substation (41).	<u>Ball Park</u> <u>Capital Cost</u>
(14)	2010 (2008)	Install 4.2 MVAR of capacitors at Waiinu Substation (36).	\$185,000
(15)	2011 (2008)	Install additional 0.6 MVAR of capacitors to existing 23 kV capacitor bank at Keanae Substation (42) (for a total of 1.2 MVAR).	\$6,000
(16)	2011 (2008)	Install 0.6 MVAR of capacitors on the Hana 23 kV Feeder between the Haiku Tap and Peahi Regulator.	\$6,000
(17)	2012 (2009)	Install additional 2.4 MVAR of capacitors to existing capacitor bank at Makawao Substation (12) (for a total of 3.6 MVAR).	\$105,000
(18)	2012 (2009)	Install additional 0.3 MVAR of capacitors to existing capacitor bank at Haiku Substation (16) (for a total of 2.1 MVAR).	\$3,000
(19)	2013	Install 0.9 MVAR of capacitors at Waiehu Substation (43)	\$9,000
(20)	2013 (deferred beyond 2013)	Switch on existing 3.6 MVAR capacitor bank on Mahinahina Substation Transformer #1 (Bkr. 1219).	\$0
(21)	2013 (deferred beyond 2013)	Install 3.6 MVAR of capacitors at Lahaina Substation (34).	\$160,000

\*Cost to relocate existing loads from Wailuku (3) and Kahului (8) Substations are unknown as it will depend on configuration of the 12 kV distribution system in those areas. Scope of work will need to be reviewed and determined by MECO.

(6)	2005	During Peak load conditions for an outage of the MGS-Waiinu 69 kV Line, use the Waiinu Tie Transformer LTC to	\$0
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raise the Waiinu 69 kV bus voltage by locking the LTC near the lower 8 position.

(7)	2005	Install 1.2 MVAR of capacitors at Makawao Substation (12).	\$15,000
(8)	2005	Raise Makawao Substation Transformer NLT position from Tap 3 to Tap 1.	\$0
(9)	2005	Install 3.6 MVAR of capacitors on both Kihei Tsf #3 and Wailea Tsf #3. These capacitor banks are only required until the MGS-Kihei #2 Line is built.	\$325,000
(10)	2006	Transfer about 1 MW of load from both Wailuku (3) and Kahului (8) Substations to Waiinu 69 kV.	Unknown*
(11)	2006	Relocate existing Waiinu Substation 69/23-12kV Transformer #2 to the 69 kV Bus. This transformer may need to be replaced with a larger MVA rated transformer. Substantial modifications of Waiinu Substation (36) will also be required.	\$875,000
(12)	2009 (2012)	Install new MGS-Kihei 69 kV Line #2. Substantial modifications of Kihei Substation (35) will also be required to accommodate the termination of the new line.	\$6,200,000
(13)	2009 (2008)	Install 0.6 MVAR of capacitors at Hana Substation (41).	\$6,000
(14)	2010 (2008)	Install 4.2 MVAR of capacitors at Waiinu Substation (36).	\$185,000
(15)	2011 (2008)	Install additional 0.6 MVAR of capacitors to existing 23 kV capacitor bank at Keanae Substation (42) (for a total of 1.2 MVAR).	\$6,000
(16)	2011 (2008)	Install 0.6 MVAR of capacitors on the Hana 23 kV Feeder between the Haiku	\$6,000

Tap and Peahi Regulator.

(17)	2012 (2009)	Install additional 2.4 MVAR of capacitors to existing capacitor bank at Makawao Substation (12) (for a total of 3.6 MVAR).	\$105,000
(18)	2012 (2009)	Install additional 0.3 MVAR of capacitors to existing capacitor bank at Haiku Substation (16) (for a total of 2.1 MVAR).	\$3,000
(19)	2013	Install 0.9 MVAR of capacitors at Waiehu Substation (43)	\$9,000
(20)	2013 (deferred beyond 2013)	Switch on existing 3.6 MVAR capacitor bank on Mahinahina Substation Transformer #1 (Bkr. 1219).	\$0
(21)	2013 (deferred beyond 2013)	Install 3.6 MVAR of capacitors at Lahaina Substation (34).	\$160,000

\*Cost to relocate existing loads from Wailuku (3) and Kahului (8) Substations are unknown as it will depend on configuration of the 12 kV distribution system in those areas. Scope of work will need to be reviewed and determined by MECO.

PUC-IR-10

Please identify with specificity the type and size of DG that can be currently deployed in Hawaii to maximize the benefits and minimize costs.

HECO Response:

“Type” refers to both type of DG application and type of DG technology. HECO presented the most common types of DG applications in its testimony at HECO T-1, page 12. Of these applications, utility-owned CHP systems offer the best opportunity to maximize benefits and minimize costs for customers and the utility, due to their high energy efficiency and widespread applicability in Hawaii. Also, Companies continue to see somewhat more limited opportunities to deploy DG for T&D reasons, such as at MECO’s Hana Substation (See HECO T-4, pages 9-10), or to install DG at substations for peaking purposes such as was done with HELCO’s four 1-MW dispersed generators. Firm DG, where the utility is able to control the operations and maintenance quality of the installation and dispatch the unit, also brings a key benefit in providing generation capacity to the system. This is especially valuable on Oahu, where there is currently an increasing need for capacity. (See HECO T-3, page 9)

DG technologies were described in HECO T-1, page 9, and in Exhibit HECO-101. As stated in the testimony, DG technologies that are fossil-fuel based include internal combustion engines, combustion turbines, microturbines, and fuel cells, although some classify fuel cells as renewable given the potential for them to run on hydrogen generated from renewable resources. DG technologies that are renewable include wind turbines and photovoltaics.

Currently, internal combustion engines are the most commonly used type of DG technology, primarily because of the maturity of the technology, their availability in a wide range of sizes from under 10 kW to over 10 MW, and their relatively low cost. Combustion turbines

are commercially available, but since they are typically above 1 MW in size, they are not as commonly used as the internal combustion engine. Microturbines and fuel cells are still in the formative stages of the product development cycle and their use is very limited.

As for the renewable technologies, wind turbines and photovoltaics, both technologies are commercially available and in use. However, they are not as common in small-scale DG applications as internal combustion engines, either because of practical siting challenges for wind turbines, or relatively high costs of photovoltaics.

PUC-IR-11

Identify with specificity existing environmental requirements which would impact the installation of DG and how this would occur? Are there any other regulatory requirements – e.g., Building Codes or zoning laws that would impact installation of DG and if so, identify these with specificity.

HECO Response:

There are numerous construction permits, operating permits and/or environmental permits and each DG project will have project specific permit requirements based on the technology, size, fuel use, location, and other factors. In addition, the DG projects would be designed in accordance with the applicable code requirements such as the Uniform Building Code, National Electric Code, National Fire Code, Plumbing Code, etc. The following discussion covers many of the possible permit requirements but it is not an exhaustive list of all Federal, State and County permits/approvals. (See response to CA-SOP-IR-5, pages 4-8)

Environmental permits and compliance requirements will vary depending on the DG technology, fuel type and site location and conditions. Possible environmental permits are listed below:

- HRS Chapter 343. Per HRS Chapter 343, development of fossil-fueled power generating facilities larger than 5.0 MW require an environmental assessment (“EA”). Based on the findings of the EA, an environmental impact statement (“EIS”) may be required for the project. The accepting agency will vary depending on who has primary jurisdiction over the proposed facility and site.
- Air Permit. The DG projects, if fossil-fueled, may require either a covered source or non-covered source air permit. The emissions generated by the various DG technologies will vary by the technology itself, including make and model number of the prime mover, as well as the fuel type proposed. As indicated in HECO’s preliminary statement of position, these emissions could include oxides of nitrogen, sulfur dioxide, particulate matter, carbon monoxide, and volatile organic compounds. If the proposed application triggers the need for an air permit, the issuing agency will be the Department of Health and possibly the Environmental Protection Agency. There are several control technologies available for each type of generating unit. These control technologies

would be examined as part of the permitting review process and are dependent on the type of air permit being considered. Typical control technologies include fuel selection, fuel injection timing, water injection, etc.

- Noise Permit. The DG projects may require a noise permit. The sound levels emanating from the DG units will vary depending on the technology under consideration as well as the make and model. If a noise permit is required, the issuing agency is the Department of Health. Control technologies available for acoustic treatment are dependent on the technology and the supplier. Sound mitigation equipment such as mufflers, baffles, insulation, etc. are often offered by suppliers. In addition, exterior sound attenuation is also available by acoustic walls, enclosures, and similar approaches.
- National Pollutant Discharge Elimination System (NPDES) permits issued by DOH Clean Water Branch, including:
  - Individual facility discharge permit – for cooling water and other industrial wastewater discharges to navigable waters
  - Construction Stormwater Permit – for construction projects larger than one (1) acre.
  - Construction Dewatering Permit – for construction dewatering to storm drains, drainage ditches or other navigable waters of the State.
  - Hydrotesting water – for discharge of hydrotest water from tank integrity testing, etc.
  - Treated Process Water – for discharges of wastewater associated with well drilling activities.
- City & County of Honolulu (C&C) Individual Wastewater Discharge permit – issued by the C&C Department of Environmental Services for sanitary wastewater connections.
- C&C Storm Drain Connection Permit – issued by the C&C Department of Environmental Services for facility connections to the C&C's storm sewer system.
- Underground Injection Control (UIC) Permit – issued by DOH Safe Drinking Water Branch for wastewater discharges to underground injection wells.
- Used Oil Management Permits – issued by DOH Solid & Hazardous Waste Branch for certain used oil management activities, including: used oil generation/marketing, used oil processing used oil transporter, etc.

Other possible environmental compliance requirements include:

- Spill Prevention Control and Countermeasure Plan requirements – EPA required plan for preventing and controlling releases from aboveground storage tanks exceeding a combined capacity of 1,320 gallons.

- Underground Storage Tank registration and management requirements – DOH Solid & Hazardous Waste Branch requirements for underground storage tanks.
- Hazardous substance reporting requirements – DOH and EPA require reporting of hazardous materials that are:
  - stored at facilities in excess of threshold planning levels (i.e., Emergency Planning and Community Right to Know Tier II reporting),
  - released to the environment above Reportable Quantities (i.e., State Contingency Plan), and
  - released, used and/or manufactured at the facility above threshold planning levels (i.e., Toxic Release Inventory).
- Testing of by-products (or waste products) – Other than testing/monitoring activities required by permits listed above, DOH or EPA may require testing of solid and liquid wastes to determine if they are hazardous. If tests show by-products to be hazardous, the facility must comply with hazardous waste regulatory requirements (regarding the treatment, storage and disposal of wastes). Additional biennial reporting may be needed if the facility meets the definition of a large quantity generator during any month during a reporting year.

The Companies also plan to conduct Environmental Site Assessments to satisfy property transaction due diligence requirements (i.e., to minimize the environmental liabilities that might be associated with purchasing, leasing or otherwise using contaminated properties).

The following is an example of a generating unit permit checklist with permit requirements which may or may not apply to a DG project.

**Example Checklist of Potential DG Project Permit Requirements**

PERMITS	FEDERAL	STATE	COUNTY
PUC Approval if Utility Involved		PUC	
Air Permitting (EPA if emissions greater than 100-tons/yr)	EPA	DOH	
HRS Chapter 343 EA/EIS if fossil fueled & greater than 5.0 MW		varies	
SMA/EA SMA Condition #21			PC
UIC-PTC PTO		DOH (SDWB)	
UIC-PTO	EPA		
CZM		CZM	
Well Construction Permit		DNLR	
Pump Installation Permit		DNLR	
NPDES Storm Water Permit		DOH	
Construction Activity		(CWB)	
NPDES Storm Water Permit Industrial Activity		DOH	
Certificate of Water Use		WRMC	
Water Use Permit		WRMC	
Parking Variance			DPWLU
Building Permits Retaining Wall Fuel Oil Containment Wall Emissions Stack Equipment Foundations Fuel Oil Storage Tank			DPWLU
HVAC		DOH	
Water Treat. & MCC Rm.			
Septic System		DOH	
Demolition of Structures		DOH	
Aboveground Tank Installation No. 2 Diesel storage tank			FD
Noise		DOH	

PUC-IR-12

What are the beneficial impacts of DG on the transmission and distribution (“T&D”) system and more importantly, how may they be quantified and assessed for value?

HECO Response:

There are several ways that DG can be beneficial to the T&D system. One of the ways is by increasing reliability. As explained in HECO T-4, pages 2-3, DG can benefit the reliability of a single customer’s electric service if it is able to operate while connected to the utility power system and isolated from the utility, which could occur if there was a T&D outage. The second way is by installing DG at targeted utility substations, which can improve the reliability of a localized area of the T&D system and can also address both generation and T&D concerns due to load growth. In the case of adding DG at Hana Substation, two diesel engine generators, which were planned to be retired, were relocated to Hana Substation No. 41. The installation of the diesel generators provided an attractive alternative towards addressing power system reliability issues for Hana Substation than installing additional transmission facilities. Refer to HECO T-4, pages 9-10. In concept, a third way that DG is beneficial is that DG could defer the need for certain T&D facilities such as lines and transformers, which may be needed to avoid overloads under contingency and projected peak conditions. If enough DG can be added and are operated reliably so that the peak load growth is reduced, then the deferral benefit might be realized. Factors such as DG diversity issues and T&D peak load planning and the customer’s commitment to the operation and maintenance of DG will affect how much the T&D facilities can be deferred. Refer to HECO T-4, pages 13-17, HREA-HECO-IR-12, COM-Companies-SOP-IR-3 and COM-HECO-DT-IR-26. There are practical considerations, however, that limit the ability of DG to be used on a targeted basis to defer specific T&D projects which include

inadequate land sites on customer or residential property where the DG may be required to address T&D criteria violations and/or reliability concerns and the ability to permit the units to operate in the manner that will reduce the load.

Theoretically, DG can also reduce system transmission and distribution losses. Refer to COM-HECO-DT-IR-28. DG could also provide voltage support as explained in HECO's Preliminary Statement of Position, page 20 and response to HREA-HECO-T-4-IR-6.

As stated in HECO's Preliminary Statement of Position, page 19, the impact of DG located at customer facilities is dependent upon specific issues such as configuration of the distribution system (i.e. radial vs. network), length of distribution lines, penetration of distributed generation on the primary circuit and the back up circuit, reliability and redundancy of customer systems, synchronous or induction generation, grounding of transformers and other equipment, and short circuit characteristics of the distribution circuit. Therefore, DG impacts need to be studied on a case-by-case basis and are included in the planning process for the T&D system.

HECO T-4, pages 5-9, explains the Companies' general T&D planning process. HECO RT-4, pages 2-14 explains in more detail how DG and CHP are considered in the Company's transmission planning process and IRP process. DG/CHP is considered in the transmission planning process on a system wide basis and included in the Company's Sales and Peak Forecast, which is the basis for calculating a load growth rate. This load growth rate determines the amount of load that the system is expected to serve at various locations of the system and this is input into a load flow model. Load flows (PSS/E computer simulations) are performed to identify transmission planning criteria violations and reliability concerns. Possible solutions are identified which include increasing transmission capacity, reduction of load through the installation of DG, CHP or DSM (above what is forecasted on a system wide basis), or a

combination of both. Load flows are re-run to determine if a solution is viable. This process was followed for the transmission planning studies filed in Docket No. 03-0417 (East Oahu Transmission Project), Exhibit 6. This process was also followed in the draft 7200/7300 Line Overload Study on the HELCO system, which was attached in response to CA-SOP-IR-15. In addition, the 10 Year Transmission Study (2004-2013) for the MECO system was completed and finalized. Please see the attached Executive Summary in response to PUC-IR-9.

For the East Oahu Transmission Project, approximately 47 MW was required to defer the Koolau/Pukele Line Overload Situation. (Refer to Docket No. 03-0417, HECO T-4, pages 81-83). The study included impacts from an aggressive CHP program of 19 MW, which was filed with the PUC in Docket No. 03-0366, assumed to be installed in the East Oahu area and concluded that the 19 MW was only about half of the required amount (47 MW) needed to defer the Koolau/Pukele Line Overload Situation and was not practical due to space and permitting issues, and cost.

For the transmission line overloads on the HELCO system, a draft study for the Waimea-Keamuku (7200 line) 69kV transmission line and the Waimea-Ouli (7300 line) 69kV transmission line is currently being performed, which includes the analysis of installing DG at HELCO Substations and utility-owned CHP installations in Kona and Hilo. Refer to CA-SOP-IR-15. The preliminary conclusions of the analysis are (1) that it is not realistic to assume that HELCO will be able to site the necessary DG units to prevent the line overload situations at HELCO-owned substations sites on the Kona coast, and (2) there will not be sufficient utility-owned CHP installed early enough to reduce the line overload on the 7300 line as a result of the 7200 line contingency and that it may require years (~2016) before the utility owned CHP installations match the utility-owned CHP requirements. (Refer to HECO T-4, page 12).

At the time the MECO 10 Year Transmission Study was conducted, there was much uncertainty in the CHP forecast, therefore the MECO 10 Year Transmission Study performed load flow simulations without CHP as the base case and included a sensitivity analysis by including CHP at specific locations on the Maui system (where it was most probable for CHP systems to be installed) to determine the effect on the MECO system. The MECO 10 Year Transmission Study concluded that CHP in specific areas of the MECO system could affect the timing of the next generating unit and therefore could 1) accelerate the need for capacitor additions at various substations (e.g., Waiinu Substation, Hana Substation, Keanae Substation, etc.), 2) defer low voltage problems in the West Maui area, which is where the CHP systems were assumed, beyond the 10-year study period and therefore defer the need for additional capacitors in the West Maui area, and 3) defer the need for a 69kV transmission line from Maalaea Generating Station to Kihei for approximately 9 years although capacitors would still be required. The study did not assess if it was practical to install the forecasted CHP systems forecasted in specific areas of the MECO system considering factors such as land requirements, permitting and costs, therefore there is some uncertainty in both where and when the forecasted amount of CHP will be installed. As stated in HECO T-4, page 15, on-site DG and installation of CHP are driven by the customer. For instance, commercial customers may be drawn to implement DG or CHP during periods when the existing building of a business is expanding, with the installation of a new facility, or at a point in time where large pieces of equipment such as the air-conditioning system need to be upgraded or replaced. The uncertainty is created because the customer's time frame to implement DG and/or CHP facilities may not necessarily coincide with the utilities need to resolve T&D criteria violations or reliability concerns.

HECO RT-4, pages 8-11 explain how the Companies already quantify and evaluate DG in the distribution planning process. Also refer to the response provided in PUC-IR-15.

In summary, quantifying and assessing the value of DG to resolve T&D criteria violations and/or reliability concerns requires detailed planning studies which incorporate a variety of possible options that include load reduction options such as DG, CHP and/or DSM. The Companies T&D planning process, which is conducted in a manner consistent with the IRP planning process, incorporates both T&D capacity options and load reduction options and the aforementioned planning studies have demonstrated this.

PUC-IR-13

What are the limits to the level of DG that the grid can absorb without adverse impacts? Please identify studies or other documentation in support of your response.

HECO Response:

The Companies have not identified total system limitations of DG on the Companies' grids due to adverse impacts on the system. However, there are some categories of potential adverse effects that the Companies recognize. For instance, depending on factors such as the location of the DG unit, DG may increase the risk of voltage regulation problems, may impact the utility's protection system and can result in unintended islanding. The impact of DG located at customer facilities is dependent on location specific issues such as: configuration of the distribution system, radial vs. network, length of distribution lines, penetration of distributed generation on the primary circuit and the back up circuit, reliability and redundancy of customer systems, synchronous or induction generation, grounding of transformers and other equipment, and short circuit characteristics of the distribution circuit. Refer to HECO T-4, pages 25-28 and HREA-HECO-IR-12. Rule 14.H. specifies levels of DG penetration that trigger additional study of a DG interconnection, because DG penetration greater than the threshold levels could adversely impact the transmission and distribution system. For instance, when the penetration of DG for a distribution feeder exceeds 10% of the peak annual KVA load of the feeder, the Rule 14.H. interconnection standards provide that a technical study be commenced. Also refer to PUC-IR-14. Other potential situations where DG could have adverse effects on the system are outlined in HECO's Rule 14.H., Sheet No. 34B-7, which include additional study if the short circuit contribution ratio of the DG facility is greater than 5% or if the DG facility is interconnecting onto the utility's network systems.

PUC-IR-14

What are the limits of bi-directional power?

HECO Response:

In responding to the question, bi-directional power is defined as a situation where distributed generation (“DG”) is installed at customer sites and/or distribution feeders and the DG units export power to the utility’s system. The generating capabilities of the DG units are greater than the load demand in the area the DG is installed, therefore creating a situation where the power from the DG unit is exported to a different part of the system and where power is imported to the same area from generation outside of the area if the DG unit(s) installed are not in operation. For purposes of this Docket, the parties participating have agreed that the use of DG for export is outside the scope for this Docket and the focus has been on DG sited at customer sites to serve the customer load and small amounts of DG at substations, which can serve the local distribution load in which power is still flowing from a central point to the customer (and therefore not considered bi-directional).

However, there are limitations on bi-directional power that the Companies have already studied. As stated on page 19 of HECO’s Preliminary Statement of Position, impacts of DG on the Company’s transmission and distribution (“T&D”) system are very complex and dependent on location and circumstances for each circuit. Also power quality and reliability of the T&D system are impacted by location of the DG and its interconnection. Given the many factors, limits on bi-directional power will be focused for specific areas. One example of limitations applies to the HRD Hawi-1 Wind Farm, which the Commission approved the purchased power agreement in Decision and Order No. 19953 on January 14, 2003. HRD Hawi-1 was a proposed 5.28 MW Wind Farm, which was to be installed at the end of a radial 34.5kV sub-transmission

line in North Kohala on the Big Island. At the time of this Application a second wind farm, which was to be located at Kahua Ranch and interconnecting onto the same 34.5kV radial line, had an existing purchased power agreement for a 10 MW wind farm (approved by the Commission in Decision and Order No. 18573, issued on June 1, 2001, in Docket No. 00-0177). In this situation, without the wind farms, power would flow from the HELCO 69kV transmission system through the Waimea transformer where it would have been stepped down in voltage to 34.5kV and serves the 34.5kV substations along the Waimea-Halaula 34.5kV line. With the wind farms, the energy from the wind farms will serve the 34.5kV substations along the Waimea-Halaula 34.5kV line and the wind farm's generation above the load demand in the area (which is typically between 2-4 MW), will be exported through the Waimea transformer onto the HELCO 69kV transmission system. There are limitations on the amount of energy that can flow from the wind farm to the HELCO 69kV transmission system. For instance in Docket No. 02-0145 (HRD Hawi-1 PPA Approval) HELCO's Application cited limitations on the Allowed Capacity of the HRD Hawi Wind Farm on page 11. The limitations on the flow of power from the wind farms onto the HELCO 69kV transmission line were due to the transformation limitations on the 10.0/12.5 MVA Waimea transformer and the current carrying capacity of the radial 34.5kV line interconnecting the two wind farms to the Waimea transformer.

PUC-IR-15

Should the design of new distribution feeders consider DG?

HECO Response:

Yes. The need for new distribution feeders are generally triggered by the need to address increasing load demand in a specific area due to customer project developments and can be attributed to the addition of new customer or increases in demand from existing customers, or because of reliability concerns on the distribution feeder. As explained in HECO T-4, pages 5-9, HECO RT-4, pages 8-11 and shown in HECO R-400, pages 1-30, the Companies consider DG in the distribution planning process.

In summary, DG/CHP will be considered in the distribution planning process through a series of orderly steps. The distribution planning process starts with a forecast of demand. The demand forecast for small geographic areas is based on historical demand, actual load data from distribution substation transformers, and current readings from each individual distribution lines. Growth rates are applied to the historical demand, load data from distribution substation transformers and distribution line readings to forecast load demand on the distribution system. Growth rates are based on a historical trend of load demand and will include near-term DG/CHP projects. Load growth is dependent on customer project developments and can be attributed to the addition of new customers or increases in demand from existing customers. Since customers make the decisions as to what and when they will build, demand forecasts for these small geographical areas will vary depending on the progress of the project and load forecasts for distribution planning are updated on a regular basis as a result of project developments. Therefore, load forecasts for the distribution system cannot be made further than three to five years into the future.

Next, given the assumptions for future demand, load flows on the distribution system can be calculated for radial distribution systems. In some instances computer simulations are performed to determine the magnitude and direction of the flow of electricity over the various distribution lines (i.e., distribution network systems). The calculated load flows and/or simulated load flows are compared against HECO's distribution planning criteria to determine where and when planning criteria violations, if any, are forecasted to occur. Finally, if any planning criteria violations are identified, then possible solutions are evaluated.

Possible solutions to address planning criteria violations include 1) additions or modifications to the distribution system and 2) load reduction options such as CHP, DSM, rate options as well as distributed generation at substation sites.

It should be noted that use of DG or CHP for distribution feeders will typically be limited because of reasons cited in HECO T-4, page 14 which include 1) DG diversity issues and transmission and distribution ("T&D") planning, 2) timing of DG and CHP installations may not coincide with the Company's requirements, 3) the customer's commitment to the operation and maintenance of DG and CHP units, 4) customers will only install DG and/or CHP if it is cost-effective and 5) there are practical issues with DG and CHP installations. Refer to HECO T-4, pages 14-17. For example, in a hypothetical new subdivision in West Oahu DG could be considered instead of the line extensions. However, diversity issues should be considered. If a single DG unit is off-line for maintenance or forced outages, then the customers served by the DG would still require a back-up feed in the form of a distribution line extension for electricity service. If several DG units are used to serve the West Oahu load growth, then the costs and space issues for the DG will need to be considered and line extensions costs would probably be less than installing several DG units. CHP could also be considered, however since the load

demand will be made of residential and small commercial customers, there would not be a large demand for the heat resources that CHP offers and installing a CHP may not be cost effective.

PUC-IR-16

Can the concept of micro-grids be made practical? Can they be effectively utilized in Hawaii?

HECO Response:

Further analyses are required in order to determine if the concept of micro-grids can be made practical and effective in Hawaii. HELCO is currently participating in a joint study with the Hawaii Department of Business, Economic Development and Tourism ("DBEDT") to assess if it is technically and economically viable to use a micro-grid approach. A micro-grid approach as defined for the study includes the use of multi-function hybrid systems that are dispatchable by the utility in combination with the use of the utility's distribution lines and transformers.

The joint HELCO and DBEDT study will look at three distribution feeders located in high growth areas on the west side of the Big Island. Preliminary results indicate that the use of DER has the potential to provide technically sound and economically viable options for these feeders, however, system integration issues and control interfaces to operate the DER as a dispatchable generation resource still need to be addressed and will not be addressed in the study. While the joint study looked at three feeders, not all feeders can accommodate DER and any proposed DER project will require an analysis to be accomplished as feeder and transmission issues need to be assessed.

Hawai'i Gateway Energy Center  
Technical Roundtable

# Summary of HELCO Studies of Energy Storage & DER Microgrids for US DOE and DBEDT

Larry Markel, Sentechn, Inc.  
20-21 October 2004

## Hawai'i/Big Island - Challenges

- Load & Generation are geographically separated
- Key transmission lines operating at capacity
- High penetration of renewable energy sources
  - Increase reserve requirements
  - Can't bring regulation on-line at light load
- Rapid load growth on distribution system

# Hawai'i/Big Island – System Reinforcement

- Transmission reconductoring
- Increase generation capacity
- Reinforce distribution system
- Energy Storage
- Microgrid – Distributed Generation; Combined Cooling, Heating, Power

PUC-IR-17

Should utilities be offered incentives to facilitate DG?

HECO Response:

While there may be circumstances where it may be appropriate to offer incentives to utilities “to facilitate DG”, presently incentives to the utility are unnecessary if the Companies are allowed to own and operate DG, including customer-sited CHP. The Companies’ testimonies have identified the potential detrimental impacts of uneconomic bypass, and the benefits of utility ownership of CHP systems. The Companies’ proposed CHP Program and Schedule CHP Tariff, if approved, would facilitate the expansion of the DG/CHP market.

As described in the Companies’ CHP Program application, if the Company installs a utility CHP system, it retains the demand and energy charge revenues from the sale of electricity (less the reduction, if any, in energy usage and demand due to the use of waste heat to displace electricity, and less the price reduction to reflect the benefits of customer-sited generation); it gains revenues from the sale of waste heat (therms) and from the facilities charge for the absorption chiller (if an absorption chiller is included in the project); and it incurs the capital, operating and maintenance costs for the CHP system installation. (The interests of all ratepayers are taken into consideration if the utility is allowed to participate primarily by structuring the program of installing utility-owned CHP systems so that non-participating customers are not burdened. This in contrast to non-utility CHP installations where only the interests of the host CHP customer and the CHP developer are considered and there is no regulatory oversight.)

A third-party CHP system, on the other hand, will cause the Company to lose revenue based on

the reduction in demand and energy charges. The energy charge recovers a substantial percentage of the Company's fixed demand and customer costs, and the lost revenues far exceed any savings the Company will see in variable operating and maintenance costs associated with the customer's reduction in load and energy. A third-party CHP installation would ultimately have a negative impact on non-participating ratepayers. (HECO T-1, page 18.)

The Companies project a larger CHP market in Hawaii if the utility is allowed to offer its proposed CHP Program. The primary basis is the broad-based customer support and demand for the Companies' CHP Program, as described on pages 19-22 of the Companies CHP Program application in Docket No. 03-0366, and on pages 24-25 of HECO T-1. The most critical factor is the sentiment from many facility owners that they do not want to own, operate or maintain CHP systems, and therefore the utility's unique model of offering utility-owned, operated and maintained CHP is appealing. Additionally, there is an appreciation by customers of the utilities' long-standing presence in Hawaii, and also its accountability as a regulated entity. For these reasons, the Companies believe that more customers will decide to proceed with CHP if the utility is allowed to offer CHP systems, ultimately increasing the size of the market. (HECO T-1, page 24.)

PUC-IR-18

How can utility distribution practices be modified to enable DG to provide distribution deferral and be compensated for it?

HECO Response:

It would be difficult to modify distribution practices to enable DG to provide distribution deferral and be compensated for it. The impact of distributed generation (“DG”) on Hawaii’s distribution system is very complex and requires detailed studies on a case-by-case basis. Refer to Companies’ Preliminary Statement of Position, page 16. In order for DG to provide “distribution deferral and be compensated for it”, the utility would have to rely on the DG unit as firm capacity. There are concerns with relying on the DG units as firm capacity. For example, there are issues on diversity of DG installations over an area, reliable operation of the DG unit and the utility’s ability to control the output of the DG which will determine if there is distribution deferral and the amount of distribution deferral. Refer to HECO T-4, pages 13-17. Issues on reliable operation and control of the DG could hypothetically be addressed in agreements. For instance, HECO T-3, pages 16-17 explains some of the performance standards, requirements and penalties in purchased power contracts for independent power producers interconnecting onto the utility system. However, the Companies’ response to HREA-HECO-T-4-IR-4 explains that it may be unlikely that 3<sup>rd</sup> party DG facilities (because they are not exporting to the grid) would be likely to enter into such agreements that would allow the utility to have some control over the facility. Refer also to HREA-HECO-T-4-IR-5 and COM-HECO-DT-IR-27.

DG could defer distribution facilities and HECO’s own distribution planning process shown in response to CA-SOP-IR-15, page 21, HECO-R-400, pages 1-30 and explained in

HECO T-4, pages 7-9 and HECO RT-4, pages 8-9, demonstrate the process of evaluating DG and CHP for distribution criteria violations and/or reliability concerns. Given the factors previously discussed concerning the issues with treating DG as firm capacity, deferral of distribution facilities using DG are not common and situations in which DG is used to address criteria violations and/or reliability concerns require a number of factors to be in place in order for the DG to be effective. For instance, installing two diesel generators, which were to be retired, at the Hana Substation was a more cost-effective alternative to addressing the Hana Substation reliability concerns than installing another 35-mile circuit. Refer to HECO T-4, pages 9-10 and COM-Companies-SOP-IR-18. The factors contributing to the success and cost-effectiveness of a DG solution, included a relatively long radial line situation, the reliability concern of the line instead of a load growth issue or the need to serve the Hana customers on a continuous basis, and available DG units at a relatively low cost (because they had been nearing the end of their useful life to serve load were to be retired).

For developments that will utilize DG to export power onto the utility grid, HECO T-4, pages 22-25, explains the concept of calculating avoided cost for the distribution system, which provides a mechanism for the DG owner to receive payment based on avoided cost. Also refer to COM-HECO-DT-IR-28. The utility interconnecting the DG would receive cost recovery for its payment to the DG facility through the utility's base rates.

PUC-IR-19

If utilities are permitted to own distributed generation through affiliates, are any changes required to existing statutes, rules and regulations governing affiliates to guard against cross subsidization, to protect ratepayers and ensure competition between affiliates and non-affiliates on equal footing? Please identify potentially applicable statutes, rules and regulations and specify necessary changes.

HECO Response:

If the utilities are allowed to own DG only through a separately capitalized affiliate, this would present opportunities for conflicting objectives between the regulated and unregulated businesses of the Companies, which would not be present if the Companies provided CHP systems services on a regulated basis

It would be more beneficial to energy consumers to allow the regulated utilities to directly own DG. The Companies' reasons for providing CHP system services as a regulated utility service were stated in its testimony and in its CHP Program application. (See HECO T-1, pages 15-16) The expertise and resources to provide such services reside in the utility. The customers desiring such services are utility customers. The objectives of the program are utility objectives. The needs of participating and non-participating customers can be served if the program is provided on a regulated basis, while the impact on non-participating customers would be a non-factor for an unregulated supplier of CHP systems. Utilities are in a better position to provide customers with the option of having the services provider be the entity that owns, operates and maintains CHP systems, which should increase the market for such systems. (See Response to TGC/HECO-SOP-IR-3).

PUC-IR-20

What costs are associated with DG interconnection to the distribution grid?

- a. If a utility overhead line is fully depreciated and upgrades or replacements are needed for distribution interconnection, does the DG customer pay for the upgrade replacement cost?
- b. Should a DG customer be required to pay for distribution system upgrades that would have otherwise occurred in the absence of a DG interconnection?
- c. Should subsequent DG customers on a particular feeder line be responsible for costs applied to the first DG customer on the line? If so, what type of crediting mechanism should be put in place for the first customer?
- d. What mechanism should be used for recovery of these costs (i.e., fixed vs. demand charges, marginal cost vs. average cost, etc...)

HECO Response:

Interconnection costs for distributed generation (“DG”) will vary based on factors such as project size and location. The Companies’ Rule 14.H. outlines the interconnection requirements which would have an associated cost. For instance, the DG facility may need to install a grounding scheme, isolation devices, interrupting devices and a dedicated step-up transformer. These interconnection requirements are specific to the DG facility being installed and will not provide benefit to the utility distribution system (other than protecting the system from the DG facility in certain circumstances). In concept, DG could defer utility distribution system upgrades given the DG is operated in a manner that it can be relied upon and consideration of factors such as diversity, reliability and controllability. For instance, HECO T-4, pages 8-9 explains how DG reduces the load served by the distribution system either on a continuous basis or during contingency situations. Reducing the load will reduce current flow and could defer the need to install transmission facilities to address criteria violations.

In a hypothetical situation where a DG is interconnecting onto a distribution circuit and would like to export power (and receive avoided cost payments from the utility for the export of its power), a technical study such as an interconnection requirements study, should be completed in order to determine the interconnection requirements. Power exported from DG would require the transformation (depending on the size of the project), protection, communication and line equipment to connect to an existing 12kV circuit such as a 12kV overhead line or 12kV underground line or a termination at a distribution substation. The costs will vary depending on the specifics of the proposed DG project. For example, a DG near an existing 12kV circuit, may only require the Company to tap into an existing 12kV circuit per the utility's interconnection requirements compared to a DG that is miles from an existing 12kV circuit, which would require the Company to construct a 12kV line extension from the closest appropriate point of the existing circuit to the DG location.

- a. As explained earlier, use of DG could reduce the load demand on distribution facilities and could defer the need to install distribution facilities on the utility system. Costs for interconnecting a DG facility operating in parallel with the utility should be paid by the DG facility. In the case of independent power producers ("IPP") wanting to export power on the utility transmission system, the Companies have conducted interconnection requirements studies to determine the interconnection requirements such as line upgrades, which the IPP has paid for in full or in part, in order to interconnect the IPP facility. In concept, if a distributed generator is interconnecting onto the distribution system, the practice of having the distributed generator pay for the distribution system upgrades necessary to interconnect and export power would be the same as an IPP interconnecting onto the transmission system. The DG facility which is exporting onto the utility grid would also pay for any

interconnection costs required to physically interconnect onto the utility system. In concept, the interconnected generator on the distribution system would receive payment for its generation by the utility and therefore could apply it towards the cost of installing the distribution system upgrade.

- b. In concept, DG should decrease the load demand on the distribution system and could possibly provide deferral of utility distribution system upgrades given the DG is operated in a manner that it can be relied upon and consideration of factors such as diversity, reliability and controllability. If the utility were evaluating DG as an option to defer distribution system upgrades, then DG with interconnection requirements (not including distribution upgrades) should be evaluated against having to install distribution system upgrades in order to provide the most cost effective measure to remedy the distribution system violations or reliability concerns. In a hypothetical situation where a DG is interconnecting onto a distribution circuit and would like to export power (and receive avoided cost payments from the utility for the export of its power), a technical study such as an interconnection requirements study, should be completed in order to determine the interconnection requirements. The requirements on the distribution system that are caused by the DG interconnecting onto the system should be the responsibility of the DG facility. If there are system problems that occur without the DG, that would remain the same or are exacerbated by the DG interconnection, then several options could theoretically be pursued. For example, the DG could 1) be curtailed during situations which cause the system problems if they are triggered (i.e. line overloads can occur during single line contingencies which is generally not the typical state of the system under normal (all lines in) situation), 2) analyze its economics of receiving avoided capacity and avoided energy payments as discussed in

HECO T-3, pages 3-7, HECO T-4, pages 22-25 and COM-HECO-DT-IR-28 and the cost for distribution upgrades and the DG could decide to pay for the improvements, which may enable the DG to receive additional avoided capital and/or avoided energy payments, or 3) decide to locate to a different location where it may not encounter or trigger distribution upgrade situations.

- c. For DG facilities operating in parallel with the utility system please refer to the response to subpart b. For DG facilities which export power onto the utility grid, HECO has not had experience with the situation described for the distribution system. Hypothetically the DG unit should be responsible for the cost of interconnecting. Refer to response to subpart a. For the transmission system, IPP units pay for the cost of the interconnection including any upgrades that are required to interconnect and are not credited for its cost to install the upgrade if another generating unit is installed on the upgraded portion of the system since the interconnection costs are considered Contribution-In-Aid-of-Construction ("CIAC") which is not refundable.
- d. Interconnection costs for DG facilities operating in parallel to the utility system should be paid for by the customer installing the DG facility prior to the utility incurring expenses to interconnect a DG facility. For DG facilities exporting power to the utility grid, as explained in response to subpart b, a DG interconnecting onto a distribution circuit to export power would theoretically receive avoided cost payments from the utility for the export of its power and the DG could evaluate the cost of the interconnection requirements with the forecasted avoided cost payments it would receive to determine if the project is economically feasible.

PUC-IR-21

Should HECO's, HELCO's and MECO's Rule 14.H on interconnection specific to distributed generation be modified to further facilitate or encourage distributed generation? If so, please identify with specificity those aspects of Rule 14.H that must be changed? Should the same interconnection rules for distributed generation apply to both the HECO companies and KIUC?

HECO Response:

The establishment of Rule 14.H. by the Companies was designed to facilitate and provides the interconnection standards, and a standard interconnection agreement to facilitate the implementation of distributed generation ("DG") and does not require modifications unless standards such as IEEE 1547 are modified. See HECO T-4, pages 28-29. HECO's Rule 14.H interconnection standards, approved by the Commission in Decision and Order No. 20056, filed March 6, 2003, Docket No. 02-0051, included modifications to the Companies' initially proposed interconnection standards based on comments received from the Consumer Advocate and the Commission. Refer to HREA-HECO-IR-10. As stated in response to HESS-SOP-IR-1 to HECO, Rule 14.H was developed based on the latest draft of the IEEE Standard 1547 and contains time frames for the initial technical review process and procedures for additional review and study processes. Refer to HESS-SOP-IR-2 to HECO. HECO also referenced other states' interconnection standards (California, New York, and Texas) when developing its interconnection standards. Refer also to HREA-HECO-T-4-IR-8 and HREA-HECO-IR-13. The Companies will perform the same technical reviews (and study process), and will meet the same technical standards for its utility CHP installations as non-utility CHP installations. Refer to HECO RT-1, pages 28-29.

HECO has not studied the KIUC system and therefore cannot comment if Rule 14.H. should be used for the KIUC system.

PUC-IR-22

What has been the experience of the parties to date with interconnecting distributed generation facilities under either HECO's, HELCO's or MECO's Rule 14.H?

HECO Response:

The experience of HECO, HELCO and MECO with interconnecting DG facilities under the Companies' Rule 14.H is discussed in HECO, HELCO and MECO's Quarterly and Annual Reports on Status of Establishing Interconnection Agreements for Distributed Generation Customers, filed in Docket No. 02-0051. As set forth in such reports, the Companies have executed interconnection agreements with 14 existing distributed generation customers (HECO - 2, HELCO - 8, MECO - 4). HECO is currently working with one existing distributed generation customer to execute an interconnection agreement, pending completion of the necessary information to finalize the technical review process, for a cogeneration unit that was installed prior to the adoption of Rule 14.H and is currently not operating. MECO is currently working with one distributed generation customer to execute an interconnection agreement, pending completion of the necessary information to finalize the technical review process, for a cogeneration unit that is planned to be in-service in June 2005. HELCO has no existing distributed generation customers without an executed interconnection agreement.

Hess Microgen LLC is the only other party to this proceeding that has had experience with HECO, HELCO and MECO's Rule 14.H. and the interconnection process for cogeneration units.

PUC-IR-23

Is the current allocation of distribution charges between customer, demand and usage charges adequate or should it be modified to accommodate DG? What is the appropriate allocation between utilities and ratepayers of revenues foregone as a result of the deployment of DG?

HECO Response:

Distribution charges are not allocated between customer, demand and usage charges. The functional costs such as the distribution costs, transmission costs, and generation costs, are allocated between the rate classes. The distribution costs are classified as demand-related and customer-related costs. Ideally, all of the customer-related costs should be collected from the customer charge and the demand-related costs should be collected from the demand charge. But this is not the case with the Companies' current rates, wherein some of these costs are embedded and collected in the energy charges as discussed in HECO T-5, pages 12 to 14. To accommodate DG, the different rate elements (e.g., customer charge, demand charge, and energy charge) should be aligned with the costs components (e.g., customer-related costs, demand-related costs, and energy-related costs) as recommended in HECO T-5, pages 14 and 15. In other words, the customer-related costs should be collected from the customer charge; the demand-related costs should be collected from the demand charge, and the energy-related costs should be collected from the energy-charge. Aligning the different charges or rate elements with the costs components will reduce lost of utility revenues for fixed cost recovery that would result from customers installing DG, and minimize the adverse rate impact on other rate payers in the future.

Additionally, depending on the extent of the DG market that develops and the availability of the required DG-related data, the DG customers may be treated as a separate rate class in the Companies' cost-of-service study for cost allocation purposes (e.g., for allocating the distribution costs). This is noted in HECO RT-5, page 5.

Regarding the appropriate allocation between utilities and ratepayers of revenues foregone as a result of the deployment of DG, the Companies will not/can not recover already foregone revenues since rates are not set retroactively. However, when rates are reset in the Companies' future rate cases, the rates will be designed to produce the total revenue requirements approved and allowed by the PUC. The utilities' total revenue requirements constitute the total costs of providing electric service and should be recovered entirely from the ratepayers.

PUC-IR-24

Should credits be offered to customers or third parties that can defer the need for localized distribution expenditures. If yes, how should these credits be awarded, calculated and administered? And how should the cost of any credits or incentives be allocated and recovered by the distribution company?

HECO Response:

For the purposes of responding to this IR, the term “localized distribution expenditures” is defined as distribution upgrades such as installing distribution lines to mitigate criteria violations or reliability concerns. Please refer to the response to PUC-IR-18.

PUC-IR-25

How can services be identified for unbundling and how should rates be calculated? Please comment on the viability of the Consumer Advocate's proposal for unbundling (Consumer Advocate Testimony, Witness Herz at 60-63). Will unbundling rates ensure that the utility recovers its cost of service from the customer benefiting from DG and does not shift costs to other ratepayers? (See, e.g., Witness Herz, testimony at 23, 60)

HECO Response:

As a result of the settlement meetings between the parties and as noted in HECO RT-6, pages 11 and 12, the Companies', the CA's, and KIUC's positions are aligned or are in agreement with regards to certain issues addressed in this docket including the issue on rate unbundling and cost-based tariffs for DG customers. A matrix of the issues and the parties' positions is provided in HECO-R-601 and the same matrix is also provided in the CA's testimony as CA-RT-100. The parties are in agreement with the following items in the matrix concerning rate unbundling and cost-based tariffs for DG customers:

Item 3.B.1. – “The Commission should require each utility to provide and have cost of service information and apply appropriate tariffs that result in a DG customer being served at a cost that is not subsidized by non-DG customers.”

Item 4.A.1.c. – “the utility's rates are such that, on a case-by-case basis, the implementation of DG will not cause the remaining customer base to subsidize DG.”

Item 10.A.1. – “The cost of service (i.e., T&D, ancillary services, etc) provided to DG customers would be identified and quantified in a cost of service study for each utility.”

Item 10.A.2. – “The level of effort and detail for the cost of service study should be balanced with the information available, the cost of developing additional data, and the magnitude of the DG market and its impact on the utility's revenue recovery and revenue stability.”

Item 10.C.1. – “Existing utility bundled rates should be supported by a cost of

service study such that DG customers compensates the utility for the costs of services provided.”

As is illustrated by the foregoing, the appropriate end goal is to implement cost-based rates for all customers, including DG customers, rather than to simply unbundle rates.

HECO RT-5, beginning on page 4, provided reasons why rate unbundling will not ensure cost-based rates for DG customers, and is not necessary to effectively deploy DG:

1. As stated in HECO T-5, page 12-14, the Companies’ current bundled rates reflect substantial subsidies. Simply unbundling rates without regard to whether the costs reflected in the bundled rates that are being unbundled reflect the true class’s cost-of-service, will not ensure cost-based rates for DG customers, could result in adverse impacts on other ratepayers in the future, and could adversely impact the deployment of DG by providing customers with the wrong price signal.
2. DG customers who remain connected to the utility grid will continue to require all the functional services from the utility, including generation, transmission, distribution, and ancillary services. The determination of cost-based rates for DG customers, or for any customer class for that matter, is dependent on the determination of the classes’ reasonable share of the costs of these functional services which are reflected in the rates of each customer class (e.g., DG customer class), and how these class’ costs of service are recovered in the rates (e.g., demand costs are collected in the demand charge). Unbundling rates in and of itself will not ensure cost-based rates for DG customers. Cost-based rates for DG customers are dependent on the determination of this customer class; fair and reasonable share of the utility’s cost of providing the various functional services, as

well as the translation of these costs into rates.

3. As stated in HECO T-5, pages 15-16, the Companies' cost-of-service study method that is used as the basis of the current bundled rates already unbundled the utilities' system costs into the function service categories. As stated in HECO RT-5, pages 5 and 6, the Companies' cost-of-service study may be expanded to include the DG customers as a separate class in the study depending on the extent of the DG market that develops as a result of the DG policy framework from this docket, as well as the extent of availability of the required data. This is based on the presumption that although the DG customers who remain connected to the grid will continue to require and receive bundled services from the Companies, the degree and level of their requirements for these services will or may be different from the customers who receive their entire electric power requirements (full requirements customers) from the Companies. For instance, the DG customers' need and requirement for transmission and distribution services from the utility will in general remain the same or similar as those for the full requirements customers. However, the DG customers' requirements for the generation and generation-related ancillary services may vary between DG customers as well as from the full requirements customers. This presumption of the cost causation differences between DG customers and full requirements customers needs to be proven and verified. The proper assessment and determination of the costs caused by the DG customers will depend on the availability of the required data such as, but not limited to, the customers' DG capacity sizes, information on the customers' generating unit availability, frequency and duration of their downtime, DG outage verification and reporting, DG

customers' load characteristics such as system peak coincident demand, and the DG customers' demand diversity. Ensuring cost-based rates for DG customers requires the accurate determination or assessment of the costs imposed by the DG customers, and how those costs are translated into rates.

(The Companies' position regarding the CA's proposal for unbundling included in the CA's direct testimony was presented in HECO RT-5, pages 2 to 8, and in HECO RT-5A, pages 3 to 10. As discussed in the referenced testimonies, rate unbundling is not necessary to accommodate DG.)

PUC-IR-26

Should the commission consider decoupling revenues from sales so that the utility is indifferent to installation of DG that has the effect of reducing sales?

HECO Response:

No, not at this time. Decoupling revenues from sales, as a general ratemaking matter, raises substantial issues and concerns. Net revenues lost due to DG installations could be recovered through a lost margins mechanism, but the Companies are not proposing such a targeted “decoupling” mechanism in this proceeding, because the Companies propose to own and operate customer-sited CHP systems on a utility basis, and object to any program in which DG or CHP systems owned by customers or third-parties would receive incentives paid by the utility (and its customers). The differences between DG and DSM are addressed in HECO RT-1, pages 42-48.

Decoupling, as a theoretical concept, has been addressed in a number of proceedings. In the IRP Framework proceeding, Docket No. 6617, the Companies noted (in their comments on the final proposals of the parties) that several of the non-utility parties proposed that the Commission consider complete “decoupling” of profits from kilowatthour sales as a solution to the revenue loss problem created by energy efficiency DSM programs (and/or to encourage conservation programs).

While the Companies agreed that net revenues lost due to the success of IRP and DSM programs should be considered in the regulatory process, they noted that general decoupling was not necessary to solve the net lost revenues problem or to implement IRP. In general, only California had substantial experience at that time with decoupling earnings from sales volume, and California had also implemented necessary corollary ratemaking provisions, including an Attrition Recovery Adjustment mechanism.

Thus, HECO contended that the Commission's framework order was not the appropriate place to address complete decoupling, and noted that the record on this issue was certainly not sufficient to support any decision on decoupling. The Commission was unconvinced as to the wisdom of adopting a decoupling mechanism, and left the matter for possible later consideration. Docket No. 6617, Decision and Order No. 11523 (March 12, 1992), pages 17-18.

The possibility of opening a decoupling docket was suggested by other parties in Docket No. 7257, regarding HECO's first integrated resource plan. HECO's position was that it was neither necessary nor advantageous to open such a docket in the absence of a specific decoupling proposal. The Commission continued to indicate the possibility of revisiting the matter at a later time. Docket No. 7257, Decision and Order No. 13839 (March 31, 1995), page 40, footnote 41.

The "devil is in the details." A decoupling mechanism has to be able to account for increases in customers, and increases in costs due to inflation and other factors. Completely decoupling revenues from sales growth would result in the constant need for rate cases.

A fundamental fact of regulated "life" is that some sales growth is necessary just to stay even -- because as a utility's customer base grows, its expenses grow with inflation, and its rate base grows faster than inflation. Rates do not have to be increased on an annual basis for the utility to have an opportunity to earn the authorized rate of return if there is sufficient growth in revenues (due to sales growth) to offset increases in operating expenses and in rate base.

Rate base often grows faster than the other factors affecting rate of return, such as sales, due to "attrition". Attrition is the process by which past inflation causes a continued erosion of the rate of return, regardless of whether or not inflation continues. Attrition causes this decline in the rate of return as utility plant is replaced at price levels higher than those experienced when the original plant items were installed, and a utility plant is added at a unit cost per unit of output

higher than the average unit of utility plant per unit of output. Attrition is caused by past inflation, geographical growth (more distribution plant per consumer), addition of non-revenue producing plant (for service and environmental reasons), and the addition of capital intensive plant. In Re Hawaiian Electric Co., Docket No. 2296, Decision and Order No. 3546 (August 19, 1974), the Commission accepted (at page 7) as a definition of attrition, a “wearing or decrease in rate of return due to capital additions or increase in expenses coupled with a slow growth in revenues, thus causing a decline in rate of return.”

PUC-IR-27

Should the electric utilities institute termination charges (exit fees) for customers who install distributed generation and if so how should they be designed?

HECO Response:

As stated in the Companies' Preliminary Statement of Position (at page 32): "While the Companies currently do not intend to propose service termination charges where customers terminate or substantially reduce the level of the electricity supplied by the electric utility (and substitute other options) to address these types of issues, the appropriateness of having service termination charges was raised in the Competition Docket, Docket No. 96-0493." As stated, the Companies currently are not proposing such service termination charges. The service termination charges discussed in the Competition Docket were identified in the Companies' Final Statement of Position filed October 16, 1998 in Docket No. 96-0493, in Attachment D (pp. 14-15), and in Exhibit 15 to Attachment D (pp. 75-78). In general, the purpose of such a charge is to recover costs incurred by the utility as a result of its obligation to serve, but stranded as a result of a customer's service termination. (See response to CA-SOP-IR-23)

PUC-IR-28

Should standby rates similar to those implemented by HELCO (see Decision and Order No. 18575, filed on June 1, 2001, in Docket 99-0207) be adopted by HECO or MECO? Is the flat fee standby charge used by KIUC an appropriate approach for other utilities? Or should the Commission repeal and prohibit standby charges?

HECO Response:

The standby rate implemented by HELCO was stipulated by the Consumer Advocate and approved by the Commission after extensive review and revision in its Decision and Order No. 18575 filed June 1, 2001 in Docket No. 99-0207. Cost-based standby rates that are easy to understand and administer and which include appropriate provisions for the different standby services such as firm standby service, non-firm standby service, and maintenance service may be adopted by HECO and MECO. Such standby rates may be differentiated by load size if there is significant diversity among DG customers in terms of standby or back-up load requirements. Further, if standby rates are adopted only for standby and/or maintenance service, the DG customers' supplemental service will be served under HECO's and MECO's applicable tariffs. Alternatively, a cost-based stand alone tariff for DG customers may be adopted that would have provisions for all of the services required by DG customers including supplemental power service, standby or back-up service, and maintenance service. Such stand alone cost-based tariff for DG customers would require reflecting the DG class as a separate rate class in the Companies' cost-of-service study, and would require more detailed data for use in developing the appropriate allocation basis.

PUC-IR-29

Please provide comments on the issues below related to standby service proposals.

- a. To the extent that standby rates are implemented (for those utilities that do not have them) or modified, should demand subscription or non-firm standby rates be included? Please comment on the viability and desirability of a non-firm or “best efforts” standby service (see e.g. County of Maui testimony, Witness Lazar at 78)
- b. Should regulated utilities be required to charge themselves or their affiliates the same standby charges with respect to the regulated utility or affiliate owned, operated and maintained distributed generation facilities?
- c. Should standby rates be the same for all Hawaii electric utilities including KIUC?
- d. Should supplemental service be distinguished from stand-by service and if so, should supplemental service continue to be charged at the otherwise applicable tariff?

HECO Response:

- a. Yes. HECO agrees that to the extent that standby rates are implemented, it should include provisions for all forms of standby service including firm and non-firm standby service, and maintenance service, and the rates for these various standby service forms should be cost-based to the extent possible.
- b. Regulated utilities such as HECO, HELCO, MECO, should not charge themselves standby rates for distributed generation they own, operate and maintain since these distributed generation units are just another form of supply-side resource that the utilities use to provide electric power service. Utility affiliates that are separate entities from the regulated utilities themselves, and who own, operate and maintain distributed generation units should be served under the same standby service tariff and pay the same standby rates as other providers of distributed generation.
- c. The standby service rate form or structure may be made similar for all Hawaii utilities. The standby rate level will be different between utilities and should be based on each utilities’

costs of providing service. Additionally, certain tariff provisions or requirements may be different between utilities depending on their specific services and operational requirements. As stated in HECO RT-5, page 12, the Companies may propose rates specific to DG customers, such as standby service rates, in its next general rate case following the Commission's issuance of its decision and order in this docket.

- d. Yes. Supplemental service should be distinguished from standby service. It can continue to be charged at the otherwise applicable tariff, or a stand alone tariff for DG customers may be implemented that would have separate charges and provisions for their supplemental service and for their standby service. The appropriate tariff form should be determined based on the size of the DG market and the availability of data that can be used to determine the cost of providing service to DG customers. Given the current DG market size, it is reasonable to continue serving the supplemental service under the otherwise applicable tariff.

PUC-IR-30

Please describe the electric utilities' current policies regarding "hook up fees" or impact fees. Should existing policies regarding hook up fees be revised so as to remove barriers to development of distributed generation? Please comment on the County of Maui's proposal regarding impact fees. (see discussion County of Maui Testimony; e.g., Kobayashi at 12; Lazar at 18-19, 33)

HECO Response:

The utilities do not have "hook up fees" or "impact fees" as proposed by the County of Maui ("COM"). The Companies' position on the COM's proposal regarding impact fees is provided in HECO RT-1, pages 49-55, HECO RT-5, pages 8-9, and in HECO RT-5A, pages 17 to 20. As discussed in the referenced Company testimonies, the COM's proposal regarding hook up fees or impact fees is the same as the COM Witness Lazar's proposal in a prior HELCO rate case (Docket No. 6999) made on behalf of the Consumer Advocate, which was rejected by the Commission. The Commission found the same proposal by the same witness discriminatory as it charged different rates for essentially the same service based simply on the customer's vintage. Imposing such a connection cost on new or expanding customers the first time creates new sub-classes of customers based on vintage. The Commission and the utility will have to implement detailed accounting for the amounts collected from new customers and distinguish between capacity additions caused by growth versus capacity additions that are necessary to replace existing capacity. Even if the Commission establishes such accounting rules, the costs per unit of generation and/or transmission capacity can be expected to change through time. They can increase or decrease depending on the current cost of equipment and possible technological innovation. How frequently should the Commission require a new computation of the impact fee to ensure that it is reasonable? Keeping in mind that each time the impact fee is recalibrated, new customer sub-classes will again be created based on vintage. Following the first

recalibration of the impact fee, you then will have three sets of customer classes based on vintage. (HECO RT-5A, pages 17-18.)

As discussed fully in the Company's testimonies, the COM's proposal is unreasonable, lacking sound economic basis, and is contrary to the principle of cost-causation and cost-based rates.

PUC-IR-31

Should a systems benefit charge be adopted to recover costs of distributed generation? If yes, how should such a charge be established?

HECO Response:

A systems benefit charge should not be adopted to recover costs of DG. Systems benefit charges are traditionally used to collect funds for 'public benefit' programs that would not by themselves cover their costs. For DG using conventional technologies such as internal combustion engines or combustion turbines, there is sufficient opportunity for adequate economic return on the projects. Such projects should justify themselves economically on their own merits without a systems benefit charge. For DG using renewable energy such as wind or photovoltaic systems, other price support mechanisms already exist such as tax credits and net energy metering. Thus, no systems benefit charge for DG is necessary.

PUC-IR-32

Will an inverted block rate design (see e.g. County of Maui, Witness Kobayashi at 12, Lazar at 86) result in better allocation of costs of new DG facilities? What are other benefits of inverted block rate design (if any) with respect to promoting DG?

HECO Response:

No. Inverted block rate design will not result in better allocation of costs of new DG facilities. Inverted block rate design is a rate structure form and it is not a cost allocation method. As stated in HECO RT-5, pages 12 to 14, the COM's proposal on inverted rates for the residential class is irrelevant to this instant docket since the residential customers are generally not the potential users of distributed generation as contemplated in this docket. The COM's proposal is not cost-based and would further exacerbate the intra-class subsidization within the residential class, with the large usage households heavily subsidizing the low usage households. As noted in the above referenced testimony, inverted rates in the form of lifeline rates have been extensively reviewed by the Commission in Docket No. 3874, and rejected in its Decision and Order No. 6696 issued on June 26, 1981. The Commission's decision and order in that docket noted that inverted rates result in "assisting lower usage households and penalizing higher usage households. Family size was shown as an important factor in determining how much electricity a family consumes. Larger families use more electricity and poverty households tend to be larger than other households."

The Companies do not see any benefits of inverted block rate design with respect to promoting DG. The COM did not provide substantive evidence on the benefits of inverted block rate design with respect to promoting DG.

PUC-IR-33

How should costs associated with distributed generation be recovered?

- a. How should the costs of fuel purchased for utility owned, customer sited DG facilities be handled? Should it be included in the energy rate adjustment clause applicable to all customers or recovered in some other manner?
- b. Should regulated utilities be permitted to include in their regulated rates the cost of distributed generation equipment and its maintenance?

HECO Response:

- a. The proposed CHP Program and Schedule CHP Tariff will utilize the existing rate structure to charge customers for electricity. Fuel costs are recovered in that rate structure via each Company's respective Energy Cost Adjustment Clause, therefore fuel costs for the utility CHP systems should also be included. As stated on pages 75 and 76 of the Companies' application for a proposed CHP Program and Schedule CHP tariff, the Companies requested that the Commission approve the inclusion of the fuel and transportation costs, and related revenue taxes, incurred under the CHP Agreements, filed pursuant to the proposed CHP Program and Schedule CHP, in each Company's respective Energy Cost Adjustment Clause to the extent that the costs are not recovered in each Company's base rates. The Companies also request that the Commission approve a modification to each Company's respective Energy Cost Adjustment Clause, avoided energy cost filing, and Schedule Q to allow the inclusion of the fuel and transportation costs, and related revenue taxes, incurred under the CHP Agreements pursuant to the proposed CHP Program and Schedule CHP.
- b. Yes. Utility DG equipment are utility assets, placed in service for utility objectives. These objectives include provision of generating capacity, deferral of capital investment in central station generation and T&D capacity, system reliability, and meeting customer needs.

In the case of CHP systems, the Companies propose to offer such systems on a regulated basis where utility ownership of such systems is cost effective and does not burden non-participating customers. This would provide customers of CHP systems with a regulated alternative. The expertise and resources to provide such services reside in the utility. The customers desiring such services are utility customers. The objectives of the program are utility objectives. The needs of participating and non-participating customers can be served if the program is provided on a regulated basis, while the impact on non-participating customers would be a non-factor for an unregulated supplier of CHP systems.

PUC-IR-34

How should the existing IRP process and the deployment of DG be synchronized to maximize the benefits of DG?

HECO Response:

Issue No. 11 in the instant docket states “What revisions should be made to the integrated resource planning process?” The position of the Companies is that no changes to the IRP Framework are required for consideration of DG. HECO will evaluate its proposed CHP Program and DG in its IRP-3 evaluation process. Please refer to the testimony of Mr. Ross Sakuda in the instant docket in the following sections for a detailed discussion of how CHP and DG will be considered in HECO’s IRP-3:

- HECO T-3, page 12, line 8, to page 14, line 8, describes the manner in which HECO’s proposed CHP Program will be evaluated in HECO IRP-3. The analysis will consider changes in utility revenues due to discounts to electric rate tariffs, facilities charges and thermal charges.
- HECO RT-3, page 11, line 6, to page 13, line 18, describes how DG and CHP will be evaluated from the generation capacity planning perspective.

DG and CHP will also be evaluated in HECO’s transmission and distribution planning processes to the extent practical. In summary, based on forecasts of electrical demand, HECO’s transmission and distribution planning criteria will be applied to determine where and when planning criteria violations will occur and to identify any reliability concerns. When these planning criteria violations or reliability concerns are identified, possible solutions are evaluated. DG or CHP are considered as potential solutions. Please refer to the rebuttal testimony of Ms. Shari Ishikawa in HECO RT-4, page 1, line 16, to page 15, line 11, for a thorough discussion of

how DG and CHP will be evaluated in HECO's transmission and distribution planning processes.

With respect to generation capacity planning, the IRP process will determine the need for new generating capacity based on a forecast of future electrical demand, the extent to which that demand can be reduced through demand-side management programs, and the extent to which the need for reserve capacity can be reduced through load management programs. Once that need is determined, various options to satisfy that need are evaluated. Those options include DG, CHP, renewable energy and central-station generation.

With respect to transmission planning, in the HECO IRP-3 process, HECO will select a few (e.g., two or three) candidate long-term resource plans, with the specific assumptions on the sizes, locations and operating costs for future central station generating units, and perform load flow analyses. In order to account for the impacts from DG/CHP in the long-term analyses, without identifying specific locations for the DG/CHP units, forecasted DG/CHP and any additional DG/CHP above what is already being forecasted will be allocated on a system wide basis using the historical loading at the transmission substations. The timing and location of transmission planning criteria violations will be identified, and the effectiveness of some possible solutions will be evaluated. Since the transmission analysis will also consider DG/CHP in the analysis, the evaluated solutions will include mainly transmission system upgrades or additions. In addition, if transmission constraints are identified as a result of the transmission analysis for the IRP processes, additional detailed studies would have to be performed outside of the IRP process for the preferred plan approved by the Commission to further evaluate, using both transmission capacity options and load reduction options, the identified constraints and the

possible solution identified in the IRP process. See HECO RT-4, pages 1 to 12, for detailed information on transmission and distribution planning in the IRP process.

With respect to distribution planning, DG/CHP will be considered in the distribution planning process through a series of orderly steps, as in the transmission planning process, but with some significant differences, which are described in detail in Ms. Ishikawa's rebuttal testimony in HECO RT-4, page 8, line 16, to page 9, line 7. There are significant difficulties in considering DG/CHP in the distribution planning analysis in IRP, as described by Ms. Ishikawa in HECO RT-4, page 9, line 24, to page 11, line 13. Finally, as explained by Ms. Ishikawa in HECO RT-4, lines 15 to 21, because of the variability and the time frame for the distribution system load forecast, distribution system impacts will not be incorporated into the long-range plan for the HECO IRP-3. However, the Distribution Planning Process is consistent with the IRP planning process and takes into consideration Load Reduction, DG at Substations and Distribution Capacity solutions on a project-specific basis.